transmission contract. The Independent Transmission Provider will assess the transmission owner for all charges and payments for providing the transmission service. The transmission owner will receive the allocation of initial Congestion Revenue Rights (or auction revenues associated with Congestion Revenue Rights) to provide protection against congestion costs for these existing contracts. If the ultimate transmission customer prefers having a direct allocation of these rights, it can convert the contract, subject to any contractual limitations, so that the customer directly receives service through a service agreement under the SMD Tariff and would take service directly from the Independent Transmission Provider.[179] We expect that the Congestion Revenue Rights or auction revenues for Congestion Revenue Rights that the transmission owner will receive in association with these contracts will be sufficient to cover increased congestion costs that would result from having the transmission owner take service under the new tariff in order to serve its wholesale requirements customers. However, the transmission owner would have the right to make a filing pursuant to section 205 of the Federal Power Act to demonstrate that its revenue requirement should be adjusted to recover additional costs caused by implementation of this provision.

375. The Commission is concerned that pre-Order No. 888 contracts could permit the parties to extend a contract indefinitely through the use of roll-over or evergreen provisions in the contracts. The Commission seeks comment on whether it should limit the ability of the parties to extend these contracts past their initial term, or if that has passed the end of the next roll-over period and, if so, what limitations are appropriate.

2. Allocation of Congestion Revenue Rights

376. The initial allocation of Congestion Revenue Rights is important to ensure that the implementation of Standard Market Design preserves the service rights of existing customers, provides access to all available capacity and minimizes cost shifts. We offer a process for this transition. First, the Independent Transmission Provider would compile a catalogue of all the existing long-term firm obligations for its transmission system that would still be in effect when Standard Market Design is implemented.[180] This would include firm Point-to-Point Transmission Service under an open access transmission tariff,[181] firm transmission under pre-Order No. 888 contracts, designated resources for network transmission service pursuant to an open access transmission tariff, and bundled retail load (which is served under an implicit contract with the transmission owner). For firm Point-to-Point Transmission Service, the existing rights would be those specified in existing service agreements. For network transmission service and bundled retail transmission service, the existing rights would be limited to the designated resources in effect at the time, up to an amount equal to the customer's current peak load since this would replicate the service the customer is currently receiving. The Congestion Revenue Rights would go to the entity taking service under the Independent Transmission Provider's tariff. In general, these customers would not be granted an initial allocation based on additions for future load growth, but would have to secure those rights. However, there are instances where the vertically integrated transmission provider has identified load growth and limited the term (and rollover rights) of point-to-point transmission contracts. We seek comment as to whether and under what circumstances load growth should be accommodated in the direct allocation of Congestion Revenue Rights. The initial Congestion Revenue Rights would be receipt point-to-delivery point obligations.

377. Next, the catalogue of firm obligations would be subject to a simultaneous feasibility test.[182] On some systems, it may not be possible to award Congestion Revenue Rights that are simultaneously feasible to all of the existing firm transmission customers on the system, because the system may be leveraging load diversity—different customers using the grid at different times—to meet the peak needs of all users. If those needs cannot all be met simultaneously, then not all customers can have annual Congestion Revenue Rights equal to their peak usage,[183] then the initial allocation of Congestion Revenue Rights would be limited to the amount that is simultaneously feasible. The Congestion Revenue Rights could be allocated between customers on a *pro rata* basis or customers could be given the opportunity to change receipt points to achieve a simultaneously feasible result, or the Congestion Revenue Rights could be restricted to certain periods.[184]

378. Either of two methods could ensure that current customers receive the value of their current contracts (actual or implicit)—direct assignment and an auction with a revenue assignment.[185] First, Congestion Revenue Rights could be directly assigned to the customers that currently have the receipt points and delivery points identified in their existing contracts (actual or implicit). Under this approach, a customer that currently has a firm point-to-point transmission contract for 100 MW from point A to point B would receive 100 MW of Congestion Revenue Rights from point A to point B for the length of its contract. A network customer or a load-serving entity serving retail load that has identified a network resource for 100 MW of capacity would receive a Congestion Revenue Right for 100 MW from that receipt point to the customer's load.[186] The delivery points would be defined as the customer's interface points with the Transmission Provider. For network contracts and implicit contract, it is likely that customers would continue service for the foreseeable future (without a contract termination date). Thus, we seek comment on what type of term should be used for purposes of the Congestion Revenue Rights allocation for these contracts.

[179] To the extent that there are contractual limitations, the customer could seek modification of the contract through a filing with the Commission.

[180] Network transmission contracts are not currently assignable because they do not consist of reservations from particular receipt points to delivery points in specific stated amounts. Therefore, some measure of historical usage on a point-to-point basis will have to be imputed to each network customer in order to assign Congestion Revenue Rights.

[181] Short-term firm contracts would expire before the implementation of Standard Market Design and would thus not be included in the catalogue.

[182] Simultaneously feasibility means that power can be simultaneously transmitted from the receipt points to the delivery points specified in the Congestion Revenue Rights in a contingency-constrained dispatch. If this power flow does not cause overloads on the system (either pre- or post-contingency), then the power flow is simultaneously feasible.

[183] Congestion Revenue Rights that give a holder different seasonal quantities could be an option in such a case.

[184] If the simultaneous feasibility tests indicate there are additional Congestion Revenue Rights that could be offered, these Congestion Revenue Rights will be offered through an auction open to all customers.

[185] For the sake of simplification, this discussion assumes that simultaneously feasible Congestion Revenue Rights could be issued to replicate current rights. If adjustments need to be made to ensure a simultaneously feasible result, the numbers may change, but the same basic methodology would be used for the conversion process.

[186] In states that have retail competition, provisions would also be needed to ensure that the Congestion Revenue Rights stay with the load. So if a new retail marketer starts serving load previously served by the local utility, the retail marketer would get a proportionate share of the Congestion Revenue Rights.

379. Alternatively, current firm customers could be given the auction revenues from the sale of Congestion Revenue Rights. Thus, the existing customers would receive the market value of those rights. Under this approach, all of the Congestion Revenue Rights available on the system would be sold through an auction. At a minimum, the Congestion Revenue Rights sold in the initial auction would have to include point-to-point obligations. If there is interest from market participants and it is technically feasible, the auction could also include point-to-point options and flowgate rights.

380. The terms of the Congestion Revenue Rights would vary. Initially, a set percentage would be auctioned on a monthly basis, another set percentage would be auctioned for six months and another for one year. This rulemaking proposes that the regions be given flexibility in setting the initial terms for the Congestion Revenue Rights sold in auctions. Since congestion patterns can change significantly after the implementation of LMP, there may be a benefit to delaying the auction of multi-year Congestion Revenue Rights until after a start-up period. On the other hand, customers may desire long-term Congestion Revenue Rights to correspond to the term of the long-term contracts used to satisfy the long-term resource adequacy requirement. We seek comment on whether we should require long-term Congestion Revenue Rights in such cases. The Congestion Revenue Rights that would be sold during the initial auction would be the set of Congestion Revenue Rights that maximizes the value of the awarded Congestion Revenue Rights based on buyers' bids that is simultaneously feasible. The revenues from the auction would be given to the customers that are paying for the embedded costs of the system through an access charge.

381. In the long-term, the auction methodology has a number of advantages over the allocation methodology in a competitive wholesale market. First, the auction methodology makes it easier for load-serving entities to change receipt points (and thus supply sources) and obtain protection against congestion costs because of the more frequent auctions for Congestion Revenue Rights. The same would also apply to sellers seeking to sell to different buyers. In contrast, if Congestion Revenue Rights are directly assigned, holders of the Congestion Revenue Rights on congested paths may be reluctant to offer these in the secondary market. This could limit the ability of new suppliers to enter the market. This could be problematic particularly with Congestion Revenue Rights held by vertically-integrated utilities. Second, experience to date has been that there is a more vibrant secondary market where Congestion Revenue Rights are auctioned rather than directly assigned.[187]

382. This proposed rule establishes a preference for the auction of Congestion Revenue Rights. After a transition period, all Independent Transmission Providers would be required to auction their Congestion Revenue Rights. However, for an initial transition period of four years, this rulemaking proposes to allow regional flexibility on this issue. During a transition period, the Independent Transmission Provider after consultation with the Regional State Advisory Committee and stakeholders in a region, could decide to directly assign Congestion Revenue Rights. At the end of the transition period, the Independent Transmission Provider would be required to submit a filing to move to an auction for Congestion Revenue Rights with the auction revenues allocated to those that pay the access charge, or justify why a longer transition period is necessary. The customer that previously had been allocated the Congestion Revenue Rights would now receive the auction revenues. The customer could participate in the auction if it wished to retain the Congestion Revenue Rights. We seek comment on whether to allow a transition period before the start of Congestion Revenue Rights auction allocations and, if so, what the length of such a transition should be.

3. Reciprocity Provision

383. In Order No. 888, the Commission included a reciprocity provision in the *pro forma* tariff. Under this provision, all customers (and their affiliates), including non-public utility entities, that own, control or operate interstate transmission facilities and that take service under a public utility's open access transmission tariff, must offer comparable (not unduly discriminatory) services in return.[188] The Commission also recognized that a public utility may deny service simply on a claim that the open access offered by a non-public utility was not satisfactory. Thus, the Commission developed a voluntary safe harbor procedure under which non-public utilities could submit to the Commission a transmission tariff and a request for declaratory order that the tariff meets the Commission's comparability (non-discrimination) standards. If the Commission found it to be an acceptable reciprocity tariff, the Commission would require the public utility to provide open access service to that particular non-public utility.[189]

384. We propose to continue this approach to reciprocity. Further, we propose to grandfather all reciprocity tariffs that the Commission previously found met the comparability standards of Order No. 888. We request comment on this proposal.

4. Force Majeure and Indemnification Provisions

385. In Order No. 888, the Commission recognized that the risk allocations regarding liability and indemnification ''must be carefully drafted so that transmission providers and customers can accurately assess and account for their respective risks.''[190] The Order No. 888 *pro forma* tariff contains a force majeure provision and an indemnification provision.[191] The force majeure provision provides that neither the transmission provider nor the transmission customer will be liable to the other when they behave properly, but unpredictable and uncontrollable force majeure events prevent compliance with the tariff.

386. Under the indemnification provision, the transmission customer indemnifies the transmission provider against third-party claims that arise from the performance of obligations under the tariff. The Commission explained that the purpose of the indemnification provision was to allocate the risks of a transaction, and costs of the risks, to the party on whose behalf the transaction was conducted.[192] Further, as the tariff did not obligate the customer to perform services on behalf of the transmission provider there was no comparable basis for imposing an indemnification obligation on the transmission provider. The Commission found it inappropriate to require the customer to indemnify the transmission provider from damages arising from the transmission provider's own negligence. Thus, a transmission customer is not required to indemnify the transmission provider in the case of negligence or

[187] New York ISO auctions Congestion Revenue Rights and PJM directly assigns Congestion Revenue Rights. MISO has also proposed to initially directly assign Congestion Revenue Rights but to transition to an auction of Congestion Revenue Rights with an allocation of auction revenues to the customers that pay the embedded costs of the system.

[188] *See* Order No. 888 at 31,760; Order No. 888–A at 30,285.

[189] *Id.* at 31,761.

[190] Order No. 888 at 31,765.

[191] *See* Sections 10.1 and 10.2 of the *pro forma* tariff.

[192] *See* Order No. 888–A at 30,301.

intentional wrongdoing by the transmission provider.[193] The Commission further explained that while it was appropriate to protect the transmission provider when it provides service without negligence, the determination of liability in other instances should be left to other proceedings.

387. Since Order No. 888, several entities have sought to revise their open access transmission tariffs to include liability provisions arguing, among other things, that no current federal forum exists for entities that are now subject to Commission jurisdiction only and can no longer seek relief at the state level.

388. We recognize that there may be a need to include liability provisions in the Commission's *pro forma* tariff in circumstances in which there are no liability provisions available in a state tariff; however at this time, we are not prepared to propose a specific provision.[194]

389. We seek comment on the following issues: Is there a need to include liability provisions in the Commission's *pro forma* tariff? Under what circumstances should liability protection be provided in a Commission open access transmission tariff (*e.g.*, should we provide such protection only where it is not available through state tariffs)? If we adopt liability provisions, should they be generic or do they need to be adopted on a regional basis? Should the standards adopted in a Commission *pro forma* tariff reflect what was previously provided under state law? How do we resolve the issue in the multi-state context of an ISO or RTO? The Commission will review the comments filed and then hold a staff technical conference in the fall to further discuss this issue.

I. Market Power Mitigation and Monitoring in Markets Operated by the Independent Transmission Provider

1. Principles and Objectives

390. In a structurally competitive market, one with many buyers and sellers who cannot influence price, the market can assure an overall efficient outcome where prices indicate the value of additional supplies and conservation. The development of structurally competitive markets is the Commission's long-term goal. However, at this stage of the industry's evolution, wholesale electric markets are not yet structurally competitive in all respects. The two significant structural flaws are the lack of price-responsive demand and generation concentration in transmission-constrained load pockets. Given these structural defects, the Commission cannot rely on the interaction of supply and demand in all instances to ensure that prices are competitive and thus just and reasonable.

391. Cost-of-service regulation is not effective for spot market pricing of commodities such as electricity. In the past, customers were served by a monopoly supplier under cost-of-service rates, in which the fixed and variable costs of a company's generation portfolio were allocated over the expected hours of service to determine a cost per kWh. But today, the power needs of load-serving entities are met through a mix of sources, including the companies' generation portfolios, and long-term and spot market purchases from a variety of sellers, including independent producers and marketers. These do not match the long-term arrangements needed for cost-of-service regulation. In this competitive context, cost-of-service regulation designed for long-term cost recovery is not well suited for determining appropriate spot market prices. When applied to spot markets, cost-of-service regulation blunts price signals and leads to inefficient investment and consumption decisions which over the long run increase costs for all customers.

392. When markets do not produce competitive outcomes, the Commission must use new regulatory tools to produce just and reasonable results. We propose new market power mitigation measures to deal with the consequences of major structural defects in wholesale electric markets, by approximating the outcomes that a competitive market would produce. These measures should function in markets that are not workably competitive, but not inhibit market operation in more competitive markets. Effective market monitoring and market power mitigation are critical elements of the Commission's plan to create and sustain competitive regional bulk power markets. Therefore, the Commission proposes rules for the spot markets to be operated by the Independent Transmission Provider to mitigate market power.

393. Market power is the ability to raise price above the competitive level.[195] This can be accomplished if the generator can withhold physical power (physical withholding) or cause physical power to be withheld through inflated bids (economic withholding).[196] Competitive prices over the long run should recover both the fixed and variable costs of efficient generating units. The challenge for market power mitigation on the supply side is to assure that it allows long-term competitive prices, which allows the opportunity to recover the fixed costs of the investment as well as the short-term variable costs of producing electricity. If some degree of scarcity pricing is not allowed, and generation only recovers short-term marginal costs, then some generators needed for reliability could fail to recover their full costs and may be retired. Worse yet, prices could be held so low that investors decline to invest in needed generation, transmission and demand-side projects because they do not see a reasonable expectation of recovering their costs.

394. The market power mitigation measures proposed here are designed to address the major structural defects in wholesale electric markets. The major structural defect on the demand side is the lack of price-responsive demand; when customers cannot respond to high prices by lowering their consumption, they cannot discipline price increases from suppliers. Absent demand response, market prices will reflect

[193] *See* Order No. 888–A at 30,299–300; Order No. 888–B at 62,080.

[194] We have included the indemnification and liability provisions from the existing *pro forma* tariff in the SMD Tariff pending review of the comments in this proceeding.

[195] The Commission's natural gas pipeline cases have used a definition of market power that examines the company's ability to raise prices significantly above a competitive level for a sustained period. Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 74 FERC ¶ 61,076 at p. 61,230 (1996); and cases cited *id* at n. 52. *See also,* Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 70 FERC ¶ 61,139 at p. 61,403 (1995) (concerning transportation and storage services). These factors recognize that it is difficult to identify market power with precision, both because it is difficult to precisely identify the competitive price (which should recover both fixed and variable costs over the long run) and because it can be difficult to isolate the impact of one entity on the competitive price. These factors also recognize that there is an implicit cost/benefit assessment to decisions to intervene in the exercise of market power. The cost of intervention in transient price increases could be greater than the public benefit gained by the intervention. Commission decisions about when to intervene in an exercise of market power are important, but need to be tailored to the circumstances of the product and the industry. In the electric industry, electricity prices can spike for one hour or a few hours in ways that are less likely for natural gas pipeline transportation and storage rates, and the consequences can be quite different. Since the definition of market power and the decision when to intervene in its exercise are analytically distinct issues, in this rulemaking the Commission incorporates the concept of when to intervene in an exercise of market power into the choice of triggers for the market power mitigation mechanisms, rather than in the definition of what constitutes market power.

[196] Market power can also be exercised by creating barriers to entry so other suppliers cannot reach the market or by causing other supplier's production costs to increase.

suppliers' bids alone, so we cannot rely on market prices to ration scarce supplies in all situations. Therefore, the market power mitigation needs to compensate for the lack of price-responsive demand in the market.

395. On the supply-side, structural problems tend to be more location-specific and time-dependent. For example, binding and sometimes unpredictable transmission constraints may restrict competitive alternatives and create opportunities for some sellers to increase prices above a competitive level, at least for any seller that knows some of its output will be required to meet load reliably. This problem is often described as a load pocket problem. In some load pockets, a specific generator may be identified as needed for reliability, which gives it a local monopoly.[197] In other situations without severe constraints, the geographic market may be broader but if little generation divestiture or entry by non-affiliated generators has occurred, concentration of ownership may remain high. Market power mitigation needs to mitigate local market power, whether it arises because of a load pocket, transmission constraints, or ownership concentration.

396. To be effective, market power mitigation measures must be applied before the fact, since remedies after the withholding has occurred are disruptive to the market and increase regulatory risk to its participants, which increases costs to customers.

397. In sum, the challenge in developing an effective market power mitigation plan is to design a plan that allows markets to function where they are competitive and, where they are not, uses market mechanisms to facilitate the transition to competitive markets. Market mechanisms can be used to approximate the outcomes that a competitive market would produce to provide the price signals for efficient investment and demand response. Because of the characteristics of electricity (it can be stored only in limited instances—pumped storage, compressed air, batteries) and the electric grid (flows follow the path of least resistance), even in regions where markets are generally competitive, transmission constraints may create non-competitive conditions during certain hours. In addition, when market power exists, the market power mitigation plan should be calibrated so that it does not inefficiently suppress prices, or mask scarcity prices, providing the wrong economic signals for efficient investment or demand response.

[197] This is also true for certain types of ancillary services (*e.g.,* reactive power) where specific generators may have the ability to exercise market power because of their location.

2. Overview of the Market Power Mitigation Measures

398. The Commission proposes a market power mitigation plan composed of three mandatory components that are specifically tailored to the structural flaws in the wholesale electric markets and a voluntary fourth measure that could apply in unusual market conditions to assure that the high prices are not the result of market power.

399. The first measure addresses the local market power problem and is similar in concept to the reliability must run agreements that exist in the ISOs today. The market monitor will identify certain conditions in which certain generators are in concentrated geographic markets created by transmission congestion or reliability needs of the grid. These would include units needed to run to support the reliable operation of the grid or a set of units owned by a small number of companies. At those times, those units will have localized market power so that when they are required to provide their energy or ancillary services to the grid their bids into the market should be capped.[198] The conditions when their power must be supplied to the grid (a must-offer obligation) and the bid cap to apply would be specified in their participating generator agreement with the Independent Transmission Provider.

400. The second component, a safety-net bid cap such as the $1000 per megawatt-hour cap currently used in Northeast markets and Texas, addresses the lack of price-responsive demand. Sellers could freely offer any amount of energy to the spot markets constrained only by the safety-net bid cap. The safety-net bid cap should allow markets to produce prices that reflect some (and perhaps a significant) amount of scarcity when shortages of reserves or power exist. But absent demand response, it sets an outer bound on suppliers' ability to exercise economic withholding.

401. The third component of the market power mitigation plan is the resource adequacy requirement discussed in Section J. The resource adequacy requirement does not directly prevent withholding, but by expanding the resource alternatives it diminishes the incentive and the ability of suppliers to practice and profit from either physical or economic withholding.

[198] This would include a broader group of units than what are often referred to as reliability must run units.

402. While it is clear that the first three measures must be part of the Standard Market Design market power mitigation plan, there may be market conditions in which a fourth measure is needed. The fourth mitigation measure would deal with situations when non-competitive conditions may exist, by examining and possibly limiting bids from individual suppliers into the day-ahead and real-time spot markets if those bids are high due to withholding rather than scarcity. Exercise of this mitigation could be triggered by predetermined conditions or triggers (such as a sustained period of prices significantly above competitive levels), or by significant infrastructure problems in the market (*e.g.*, sustained tight reserve conditions, as might be due to drought). This mechanism is like the Automatic Mitigation Procedure (AMP) used by the New York ISO, and adopted recently for the California ISO. This mechanism would not be required for every region but may be adopted if the market monitor's analysis determines this measure is needed.

403. The implementation of the market power mitigation plan summarized above and described in more detail below will rely on the results of an initial competitive market analysis by the Independent Transmission Provider's market monitor in each region. This will identify at the outset the persistent load pockets or other conditions that create local market power. This analysis will be filed with the Commission as part of the implementation process for Standard Market Design and subject to comment from all interested parties. After Commission review, it will form the basis for the mitigation measures that are applied by the Independent Transmission Provider. It then will be updated annually to review the continuing effectiveness of the market power mitigation.

404. The market power mitigation measures proposed rely principally on mitigating market power in spot markets. Mitigation would only apply to products traded in the spot markets operated by the Independent Transmission Provider, not to products traded under bilateral contracts outside the Independent Transmission Provider's spot markets. This is the least intrusive framework for market power mitigation but at the same time provides very effective protection against market power.

405. Although power and operating reserves purchased in the organized spot market are only a small percentage of total purchases, mitigating the organized spot market is an effective

way of mitigating market power generally.[199] Bilateral contracts generally reflect buyer and seller expectations of prices in spot markets. Therefore, market power mitigation in the organized spot market will effectively discipline market power in bilateral markets as well.[200] However, if spot market prices are over-mitigated, it may weaken incentives for buyers to contract in bilateral markets and expose spot market prices to greater price volatility. Regular reassessment of the market power mitigation practices can prevent this outcome, and, as discussed *infra*, the market monitor will be required to annually reassess the effectiveness of the market power mitigation.

3. Market Power Mitigation for Local Market Power

406. Local market power principally arises either from the concentration of generator ownership within a load pocket, or the need for local units to operate to assure system reliability and stability within the load pocket. Local market power can arise from both persistent and foreseeable congestion, or from sporadic transmission congestion. Although local market power can arise from these different conditions, the mitigation method proposed here can be effective at mitigating the local market power regardless of how it arises.

407. In the existing ISOs in California and the Northeast, participating generator agreements are used to set out the operating terms, conditions and obligations concerning the dispatch of a generating unit, serving principally a reliability purpose. Under the Standard Market Design *pro forma* tariff all generators dispatched by the Independent Transmission Provider would enter into a participating generator agreement.[201] Standard Market Design will require these participating generator agreements to include provisions to mitigate local market power.

408. The participating generator agreements, which would be filed with the Commission, would identify the non-competitive conditions when the generator with local market power would be required to offer its energy either by scheduling a bilateral transaction or by offering all available energy to the spot markets. This would be a must-offer requirement. The requirement would apply when the generator's power is needed to maintain the reliable operation of the grid, and also when there are insufficient competitive alternatives. The participating generator agreement would specify the conditions that would give rise to a generator's must-offer requirement, and would also specify bid caps that would apply when the generator was required to bid into the day-ahead and real-time markets. In non-competitive conditions, the generator's bids could not exceed the capped values. Although the participating generator agreement may restrict a generator's energy and operating reserves bids, the generator would still receive a market-clearing price and additional revenue to cover start-up and no-load costs.[202] The capped bid could also set the market clearing price.

409. In addition to the bid caps specified in the participating generator agreements, local market power also will be limited through bilateral contracts between load-serving entities and the generators. Under the resource adequacy requirement, load-serving entities must have enough resources to meet their demand to ensure the reliability of the grid. It can be expected that some of those resource requirements will need to be fulfilled with contracts with generators within their load pocket to ensure that the resource is deliverable during peak or congested periods. Bilateral contracts are an effective way for a buyer to mitigate the market power of a seller.[203] The load-serving entities can be expected to include provisions in these contracts specifying when a generator must run to meet any reliability needs in that location and the price to be paid. Whenever a generator is scheduled to run under a bilateral contract, this will fulfill its must-offer obligation in the participating generator agreement with the Independent Transmission Provider.

410. Under the participating generator agreements, when conditions are not competitive, that is, when there are insufficient alternatives available to meet load in that location, a generator must run to provide all its available capacity to the grid, either by scheduling a bilateral transaction or bidding into the spot market. The need for the generator to be producing could be identified either in the day-ahead market based on projected system conditions or in real time. In the day-ahead market, all available capacity would include all capacity not sold bilaterally and scheduled or on an outage. In the real-time market, all available capacity would include all non-producing capacity (not delivered to the market) *i.e.*, capacity not on a planned or forced outage.[204]

411. The Commission invites comment on how to structure the local market power mitigation, particularly on how to define the noncompetitive conditions which should trigger the mitigation, and on how bid caps should be structured for generators operating under a participating generator agreement.

412. There are some options for dealing with the risk of a forced outage inside a load pocket. One is for a portion of available day-ahead capacity to be exempt from the bid-in requirement to reflect forced outage risk in real time. Another possibility is to allow generators to provide all available capacity in real time at a capped bid in lieu of bidding in the day-ahead market to accommodate generators that have significant risk or opportunity costs. A third option would vary depending on whether the generator receives a reserve capacity payment. If the generator receives a capacity payment, that payment compensates for the outage risk so the generator should be obligated to deliver energy or to pay for substitute supply from some other source. If the generator does not receive a capacity payment, then it should not have to bear the risk for a legitimate outage. Units declaring a forced outage would be subject to audit by the market monitor. If the outage is found to be unjustified, then the generator should be subject to a penalty. The Commission requests comment on the penalty that would be appropriate to deter unjustified forced outages.

4. The Safety-Net Bid Cap

413. If bid-in capacity is generally insufficient to meet both operating reserve requirements and load, capacity rights associated with the resource adequacy requirement may be exercised by load-serving entities that have secured sufficient capacity so that they will not be interrupted. However, in this situation, lack of demand response can

[199] Stoft, Steven. *Power System Economics.* New York, NY: Wiley-IEEE Press, 2002, Section 2–4.5, ''How Real-Time Price-Setting Caps the Forward Markets,'' p. 150.

[200] Relying on mitigating market power in the spot market has been an effective mitigation method in the New York ISO under its AMP, and the California ISO since May, 2001.

[201] SMD Tariff Section A.9.2.

[202] SMD Tariff section F.1.11. The generator's legitimate minimum run times would also be honored under the provisions of SMD Tariff section F.1.5.

[203] *See* Comment of the Staff of the Bureau of Economics and the Office of the General Counsel of the Federal Trade Commission, Docket No. RM01–12–000 (July 23, 2002).

[204] Under the Standard Market Design tariff, all units scheduled day ahead under a must-offer obligation, but not needed in real time would get paid their start-up and no-load costs.

result in dramatic increases in market-clearing prices, even with comprehensive mitigation on the supply-side, *if* imports can bid in at unrestrained levels. In this case, imported power from adjacent markets could set a market-clearing price above the marginal cost of the highest cost unit dispatched within the market.[205]

Current markets in the Northeast and Texas rely on a $1000 per megawatt-hour bid cap, regardless of market conditions, as a safety-net that may be binding in this situation. The Commission proposes to adopt a safety-net bid cap as part of the market power mitigation plan here. Under this proposal, no bid to supply can exceed this level, regardless of cost or risk or location, even if the market is confronted with a genuine operating reserve shortage. However, if the monitor establishes that some units may provide power at a cost that exceeds the safety-net, a higher price for those units would be justified. In California, for example, imports are not allowed to set the market clearing price. However, in the market power mitigation framework proposed here imports would be allowed to set the market clearing price in order to get a proxy for a scarcity price, up to a capped value. If requirements cannot be satisfied with bid-in imports that would be subject to the safety-net bid cap, then load that has not met its resource adequacy requirement should be penalized as described in the Resource Adequacy section. A safety-net bid cap, such as the $1000 per megawatt-hour cap in the Northeast and Texas, can serve as a proxy scarcity price under Standard Market Design. The Commission requests comment whether the safety-net bid cap should be uniform across an interconnection, so that there would be one cap applicable in the East and another applicable in the West.

414. Comment is requested on how to determine an appropriate value for such a cap. It is important to examine the implicit trade-off between bilateral capacity payments, the safety-net bid cap and local market power mitigation. That is, a bid cap that constrains scarcity prices would be expected to translate into higher bilateral capacity payments under a contract to fulfill the long-term resource adequacy requirement. With a higher safety-net bid cap, perhaps one based on the value of lost load, smaller bilateral capacity payments would be required to maintain the same level of resource adequacy in the absence of price.

5. Mitigation Triggered by Market Conditions

415. The Commission proposes a fourth voluntary market power mitigation measure which may be recommended by the market monitor during the Standard Market Design implementation process, or any time thereafter. This measure, if needed, would apply to unanticipated and sustained market conditions that would give the ability and the incentive to exercise market power. For example, extreme supply or demand conditions to which the market cannot quickly adapt, such as the loss of significant hydropower capacity because of drought, or force majeure events such as a major transmission line outage. These kinds of events, which are not transitory, can provide opportunities to exercise market power even in a market that is normally workably competitive. It may be appropriate for other conditions to trigger this mechanism. We seek comment on what these triggers should be. Although market-clearing prices would be expected to rise in these situations, and perhaps sharply and significantly, it may be important for the market to have the assurance that the price increases are attributable to the extreme circumstances and not to the exercise of market power. An AMP mechanism such as those approved by the Commission in New York ISO and California could provide this kind of assurance.[206]

416. This kind of mechanism may not be necessary in every region. If a market monitor proposes such a mechanism, the proposal must include the specific triggers that would be used to initiate this form of market power mitigation along with the details of the mitigation method. Since this form of market power mitigation is for temporary market conditions, it will be equally important for the market monitor to indicate the criteria to determine when the market has returned to normal competitive conditions and this market power mitigation method will be suspended.

417. The details of this market power mitigation method, including the triggers, would be set out in the Independent Transmission Provider's tariff. If market conditions developed that satisfied the pre-determined triggers for the mechanism, it would be the market monitor's responsibility to give notice to the public and the Commission that the tariff mechanism had been triggered. The mechanism would then automatically take effect until the conditions developed that satisfied the pre-determined triggers for the suspension of this market power mitigation mechanism. If a market monitor proposes to use this form of market power mitigation, the details of the mechanism and the triggers would be subject to comment by all interested parties, and review by the Commission.

6. Establishing Bid Caps or Competitive Reference Bids

418. The mitigation for local market power, through the participating generator agreements, relies on must-offer obligations to mitigate physical withholding and bid caps to mitigate economic withholding. Mitigating economic withholding entails determining appropriate bid caps for all bid-in parameters.[207] The unit-specific bid caps in the participating generator agreements serve as proxy competitive bids for energy, regulation service, and operating reserves, and for other unit-specific operating parameters such as minimum run times and high and low operating levels. Bid caps should reflect the marginal cost—including opportunity cost—of offering all capacity, including power that may be supplied only under limited conditions. Other bid-in parameters should reasonably reflect operating conditions consistent with good engineering practice under competition.

419. The development of bid caps, especially for generators with significant opportunity costs such as hydropower and energy-limited units, is difficult and can be controversial. Nevertheless, this mitigation plan would require that each generator, including hydropower and energy-limited units, that may have local market power would need to have an agreement establishing bid caps for all bid-in parameters if its power is needed for the grid or local market power mitigation is necessary.

420. The Commission has approved several options for setting default energy bids that in some circumstances serve as energy bid caps. They include: (1) Default bids based on various averages of previously selected in-merit bids; (2) default bids based on various cost measures, usually a measure of operating cost adjusted for fuel costs;

[205] Generators outside the region would not have participating generator agreements with the Independent Transmission Provider, with provisions for addressing local market power, and neither would marketers.

[206] *See* California Independent System Operator Corp., 100 FERC ¶ 61,060 (2002). *See* New York Independent System Operator, Inc. *et al.,* 99 FERC ¶ 61,246 (2002). Although AMP was in effect in all of New York, it was only triggered on four occasions, reflecting conditions in eastern New York.

[207] These same considerations would apply if the Commission adopted an AMP-like mechanism with bid caps or competitive reference bids.

and (3) default bids agreed through contract or negotiation. For many fossil-fired units, an estimate of operating costs plus a margin, such as ten percent, could provide a reasonable bid cap for a unit's energy bid when competitive forces cannot be relied on, similar to PJM's approach for mitigating reliability must run units.[208] Although fossil-fired units may have opportunity costs not fully reflected by operating costs, an adder, such as that used by PJM, is one way to allow flexibility to respond to these uncertain costs. The Commission requests comment on whether the level of the adder should be reviewed on a region-by-region basis or if the Commission should establish a uniform adder, and if so, at what level.

421. For peaking units that are likely to set market clearing prices when they are dispatched, the must-offer requirement coupled with mitigation that sets bid caps at marginal cost could result in revenues that fail to recover fixed costs over a reasonable period of time. Although such units may recover additional revenue in capacity and reserves markets, bid caps for these units could also reflect a ''scarcity'' premium or adder to compensate for the lack of price-responsive demand that would otherwise set the price when these units were dispatched. The average cost of a new peaking unit at a given location operated over a given number of hours could form the basis for setting such a premium. This kind of adjustment to bid caps for peaking units could help support reliability until demand-side measures for responding to price were more fully incorporated in markets. The Commission requests comments on whether this approach or other adjustments to bid caps for peaking units might usefully substitute for demand response in the near term.

422. For hydropower and other energy-limited resources much of the difficulty in determining an appropriate energy bid cap for these units comes from the difficulty of assigning a value to their temporal opportunity costs. However, the times when it would be necessary for the transmission provider to call on power from these sources are likely to be times when prices are high and these units would want to be scheduled in any event. At all other times, hydropower units, in particular, should be offering all available capacity as operating reserves since their marginal operating costs are close to zero, but they may have high temporal opportunity costs. In other words, there appears to be no economic reason why such units should not always be fully committed either to the bilateral market or spot markets for operating reserves. Consequently, it appears unnecessary to cap energy bids from such resources below the safety-net bid cap as long as their bids to provide operating reserves were always in-merit. Alternatively, other energy-limited resources might be allowed to submit a bid that states a total megawatt-hour availability over the day and allow the market operator to schedule the power from the unit in the hours when the price is highest. Comment is requested on these and other approaches to establishing reasonable caps for energy bids.

423. Another alternative for hydropower, and other energy-limited resources, would be for the unit operator to submit a seasonal or monthly schedule for when the unit would not be expected to operate. This would enable, for example, hydropower units to specify the periods when they would expect to need to preserve water or flow water to satisfy environmental conditions. While these units have many legitimate competing needs for the water flow, it is still possible for a hydropower generator to engage in physical or economic withholding. In the existing ISOs, generators must submit a schedule for planned outages, which is coordinated by the ISO to ensure that outages occur when they are the least disruptive to the markets. The Independent Transmission Provider is expected to continue to perform this outage coordination function under Standard Market Design. Scheduling outages in advance, coupled with auditing by the market monitor, would provide a way to evaluate whether failures to run were from withholding or legitimate limitations. For hydropower units, for which the marginal costs are primarily opportunity costs, this method may be a sufficient check against withholding so that it might be unnecessary to have a bid cap for these units. The Commission requests comment on these alternatives.

424. Any parameters that a generator may include in its bid may require a cap or other restraint. For example, PJM caps regulation service at $100 per megawatt-hour, and New England uses energy prices to cap prices for spinning reserves. Standard Market Design would also allow availability bids for these products. The participating generator agreements should also contain bid caps for these operating reserves when they are needed for the operation of the transmission system and non-competitive conditions exist. However, the Commission requests comment on how to identify the options for determining competitive bid caps for regulation service and operating reserves, including availability bids, that should be established for day-ahead and real-time markets.

425. In the New York and PJM day-ahead markets, the unit-specific energy bid cap applies to the day-ahead market where separate bids for start-up and no-load costs are also available and would also be available under Standard Market Design. Market power mitigation should also establish caps for these bids and a variety of bid-in operating parameters, such as low and high operating levels and minimum run times, if non-competitive circumstances would permit sellers to manipulate these parameters to get unjustified higher up-lift payments. PJM, for example, does not mitigate the start-up and no-load bids or certain operating parameters, but it only allows units to change these values once every six months. New York permits greater flexibility and uses various screens to assess whether a seller is behaving non-competitively and should be mitigated.

426. Several approaches could be used for establishing bid caps for these particular parameters. One possibility would be to rely on engineering data, such as from the manufacturer about the specific type of unit, to establish caps for start-up and no-load bids and certain operating parameters, and give generators the flexibility to bid within those ranges without mitigation. These ranges would also be included in the generators' participating generator agreements. Just as with energy bids, a bid above the range *could* be mitigated *if* the bid raised market-clearing prices or uplift payments above a competitive benchmark level by a significant amount. Because factors that might cause generators to modify start-up and no-load bids and parameters such as minimum run times generally are thought to be less variable than factors that may influence energy bids, caps for these variables may be quite tight.[209] In fact, PJM's approach to permit changes to these parameters once every six months may be a simpler alternative that does not unduly restrict competitive generator behavior. Comment is requested on this approach and on other ways to prevent sellers from manipulating these bids and operating parameters to increase market-clearing prices and uplift payments.

[208] This method may not work for fossil-fired units that are only permitted to run a limited number of hours due to environmental restrictions. These energy-limited resources are discussed below.

[209] For example, energy prices could change frequently because of differences in the cost of fuels such as natural gas.

427. In the implementation filing, the market monitor would propose tariff language that sets forth the process for setting the bid caps for individual units or any formulas that might be used for this purpose. The market monitor would be responsible for collecting and verifying data from these units to establish appropriate caps for energy bid values consistent with the procedures in the Independent Transmission Provider's tariff. This could be controversial, especially for generators in load pockets that may effectively face ''mitigation'' in most situations. The Commission requests comment whether the Commission should establish a formula for determining the bid caps or whether the Commission should review the proposals developed in each region.

7. Exemptions

428. It is appropriate to exempt certain sellers from the market power mitigation. Specifically, sellers who control a small amount of capacity in the market, for example no more than fifty megawatts, would be exempt from mitigation. Sellers with little capacity would have little incentive to exercise market power since a non-competitive bid could eliminate their only unit from the dispatch. However, the Commission requests comment whether any other sellers should be exempt from the mitigation because they have insufficient incentives to withhold.

8. Monitoring

429. Market monitoring should be conducted on an on-going basis by a market monitoring unit that is autonomous of the Independent Transmission Provider's management and market participants. The market monitoring unit may be located within the offices of the Independent Transmission Provider, to permit easy access to the market data and operations personnel, or it may be physically located elsewhere.

430. The market monitor will be expected to report directly to the Commission, and the independent governing board of the Independent Transmission Provider. This will include reporting at regular intervals on the general performance of the markets in its region and reporting, on a timely basis, observed attempts at market manipulation or factors that impair the efficiency of the market. Although the market monitor will be accountable only to the Commission and the governing board, it should share its analyses and reports with the management of the Independent Transmission Provider and the Regional State Advisory Committee. This will enable the committee to carry out its advisory functions in an informed manner.

431. The market monitor must focus both on the functioning of the markets run by the Independent Transmission Provider as well as the conduct of individual market participants. The market monitor should focus on identifying factors that might contribute to economic inefficiency. Such factors include market design flaws, inefficient market rules, entry barriers to new generation, including distributed generation, barriers to demand-side resources, transmission constraints and market power. In monitoring for exercises of market power, the market monitor should focus principally on detecting economic and physical withholding (as distinct from the normal operation of supply, demand, and true scarcity). For entities that own both transmission and generation assets, withholding behavior could include both generator and transmission outages. For example, instead of directly withholding a generator's power, a market participant with transmission assets could effect the same end by derating a transmission line needed to deliver the generator's power to the market. Monitoring should be designed to detect this kind of behavior.

432. The Commission requests comment on whether the market monitor should also be responsible for monitoring the Independent Transmission Provider's operations, in addition to the markets and the market participants. Specifically, should the market monitor evaluate whether the Independent Transmission Provider treats market participants neutrally, without undue discrimination?

433. To meet its responsibilities, the market monitor must have the ability to collect and evaluate necessary data provided by the Independent Transmission Provider and market participants. The market monitor would have the responsibility to propose to the Commission, and the Independent Transmission Provider's board changes to market rules, if they provide inefficient incentives to market participants, and to promptly identify circumstances that may require additional market power mitigation so that remedies can be put in place prospectively.[210] The market monitor would also be required to provide a comprehensive analysis and report of market structure and individual generator conduct in the spot markets, at least annually, to evaluate the overall efficiency of spot market operations, the market for Congestion Revenue Rights, and how the balance between resources and demand in the region affects the market's ability to efficiently serve load at least cost. In addition, the market monitor must also annually assess the effectiveness of any mitigation actions taken and review the terms, conditions, and bid caps in the participating generator agreements. Finally, the market monitor must engage in surveillance to insure that market participants comply with the rules in the Independent Transmission Provider's tariff.

434. The work and findings of the market monitor must be integrated into the regional planning process. The market monitor's analysis of the markets will identify load pockets and can help provide direction for needed investment in generation, including distributed generation, demand response capability, and transmission infrastructure to improve the competitive structure of the markets.

435. The Commission proposes here the basic elements of a market monitoring plan to be used by each market monitor. The Commission staff will convene a conference in the Fall to discuss and further develop the essential elements that should be required in a standard market monitoring plan. After getting additional public input at the conference, Staff may propose additional detail for the market monitoring plan, which the Commission may adopt, after an opportunity for public comment.

a. Framework for Analyzing Market Structure and Market Conduct

436. The Commission intends to require the use of a core set of questions and analytical techniques to be used by each market monitor to assess market structure, participant behavior, market design, and market power mitigation. This will facilitate inter-regional comparisons. Examining this core set of issues using techniques reflecting ''best practices'' would be an essential part of the monitor's responsibilities that allows inter-regional comparisons. However, specifying these core requirements here should not prohibit or discourage monitors from expanding their analyses where regional differences or unanticipated events warrant it. In fact, because markets and monitoring are in a formative stage, the Commission would need to continue to facilitate communication between market monitors to share insights and develop common approaches.

437. An important focus of market monitoring will be structural market

[210] The changes would only go into effect after Commission approval.

conditions since the Commission's ultimate goal is to foster structurally competitive regional bulk power markets. Academic analysts and market monitors have examined the competitiveness of current spot markets using various approaches and data. Some have focused on developing a simulated competitive benchmark that can serve as a reasonable measure of the market's overall efficiency.[211] Others have examined whether specific generator bidding behavior has been consistent with profit maximization under competitive conditions.[212]

438. Some monitors have estimated whether average generator profitability would cover costs of a gas-fired peaking unit and provide sufficient inducement for entry.[213] Most monitors also track bidding patterns so that sudden, inexplicable changes can be investigated promptly to evaluate whether market power is a cause of the change.[214] Monitors also track changes in concentration, unplanned generator and transmission outages, and changes in various operating parameters that may signify market power problems.[215] Although the reports have been very useful in enhancing our understanding of a wide range of issues, the approaches have been varied, key questions have been framed differently and, importantly, the markets have not had the same design. As a consequence, results have not been comparable across markets. With the widely varying market designs of the past, greater comparability across regions was not feasible. However, these analyses have served as a useful starting point for developing a standard analytical framework.

439. The Commission proposes to require each monitor to perform a structural analysis of the region that would include: (1) Market concentration including by type of generation, (2) conditions for entry of new supply, (3) demand response, and (4) transmission constraints and load pockets that give sellers the ability and incentive to exercise market power. This analysis would be performed prior to the implementation of the Standard Market Design, in order to implement the market power mitigation. It also would be performed annually to reassess and adjust the market power mitigation, and to evaluate the conditions of the market.[216]

440. In addition, the Commission proposes to require an annual assessment of the performance of the markets operated by the Independent Transmission Provider. This assessment would use a competitive benchmark to assess market performance as an additional means of assessing the effectiveness of the market power mitigation.

441. Comment is requested on how the monitor should address these and other topics, to develop useful measures that permit inter-regional comparisons. For example, concentration measures stratified by generator type might better identify competitive alternatives under various demand conditions. Estimates of generator profitability, such as PJM and ISO-New England have used in the past, might be a useful measure of incentives for generator entry. These estimate the degree to which a hypothetical unit operating in all profitable hours would have recovered its costs. Although it is not a definitive profit estimate for any particular generator, it may be a useful measure for comparing incentives for generator entry across market or regions.

442. A core set of questions and analytical techniques must also be developed for monitors to use to evaluate conduct of market participants in the transmission and spot markets operated by the Independent Transmission Provider. Analysis of generation and transmission outages is central because these can be forms of withholding. Because some owners of generation also own transmission, monitors must review any planned transmission outages, for example, to make sure that scheduling outages could not be used to enhance or create opportunities to exercise generator market power. Analysis of generator conduct might also include a review of bidding behavior in the spot markets operated by the Independent Transmission Provider to identify any auction design flaws that may give market participants an unanticipated incentive and ability to manipulate market-clearing prices or up-lift payments. The monitor should also evaluate the effectiveness of the participating generator agreements in mitigating market power where market structure is not sufficiently competitive.

443. Finally, the monitor must analyze the operation of the congestion management system and the market for the resale of Congestion Revenue Rights for evidence of market power or manipulation. The monitor must also assess whether those who collect congestion revenues are in a position to influence transmission expansion plans that can affect congestion revenues and report on the incentive structure of those arrangements.

444. Any flaws in the market rules that may be identified by the monitor and any market participant conduct that indicates the ability to exercise market power under the market rules in effect would be remedied prospectively after Commission authorization of changes to the market rules. However, if the conduct violates existing rules, the market monitor must have the necessary tools to investigate the conduct and to penalize it. These will be discussed in the sections below.

445. An important adjunct to the market power mitigation and monitoring plan will be a clear set of rules governing market participant conduct with the penalties for violations clearly spelled out. The Commission proposes to require the Independent Transmission Provider to include in its tariff certain minimum behavioral rules, which will be monitored by the market monitor. These will include, at a minimum, the following rules:

(1) *Physical Withholding:* Entities may not physically withhold the output of an Electric Facility (Generating unit or Transmission Facility) by (a) falsely declaring that an Electric Facility has been forced out of service or otherwise become unavailable, or (b) failing to comply with the must-offer conditions of a participating generator agreement.

(2) *Economic Withholding:* Entities may not economically withhold by submitting high bids that are not consistent with the caps specified in the tariff or the participating generator agreements.

(3) *Availability Reporting:* Entities must comply with all reporting requirements governing the availability and maintenance of a Generating Unit or Transmission Facility, including proper Outage scheduling requirements. Entities must immediately notify the Independent Transmission Provider when capacity changes or resource limitations occur that affect the

[211] *See, e.g.*, Borenstein, S., J.B. Bushnell, and F. Wolak (1999). ''Diagnosing Market Power in California's Deregulated Wholesale Electricity Market.'' POWER Working Paper PWP–064, University of California Energy Institute, *available in http://www.ucei.berkeley.edu/ucei/pwrpubs/pwp064.html*.

[212] Joskow, P.J., and E.P. Kahn (2001). ''A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000.'' NBER Working Paper No. W8157. National Bureau of Economic Research.

[213] *See, e.g.*, PJM Interconnection State of the Market Report 2000.

[214] *See, e.g.*, New York Market Advisor Annual Report on The New York Electricity Market for Calendar Year 2000, by David B. Patton, Ph.D., Capital Economics, April, 2001.

[215] *See, e.g.*, Annual Market Report, May 2000–April 2001, ISO New England, August 1, 2000.

[216] The monitor should particularly pay attention to concentration in the regulation and operating reserves markets, and consider the amount of supply relative to demand, and propose specific market power mitigation measures for these markets if necessary.

availability of the unit or facility or the ability to comply with dispatch instructions.

(4) *Factual Accuracy:* All applications, schedules, reports, or other communications to the Independent Transmission Provider or the Market Monitor must be submitted by a responsible company official who is knowledgeable of the facts submitted. All information submitted must be true to the best knowledge of the person submitting the information.

(5) *Information Obligation:* Entities must comply with requests for information or data by the Market Monitor or the Independent Transmission Provider that are consistent with the tariff.

(6) *Cooperation:* Entities must assist and cooperate in investigations or audits conducted by the Market Monitor.

(7) *Physical Feasibility:* All bids or schedules that designate resources must be physically feasible within the limits of the resource, *i.e.*, the resource is physically capable of supplying the energy, ancillary service, or demand response needed to fulfill a schedule or bid according to the physical limitations of the resource.

446. These rules must be accompanied by predetermined penalties, as discussed below in the Enforcement section.

b. Data Requirements and Data Collection

447. Data collection should be targeted to providing monitors with information necessary to answer the required questions covering critical issues regarding market structure, participant behavior, and market design. These data would be acquired from various public sources and in the normal course of operating the markets. They would include: (1) Market statistics and indices, such as market-clearing prices and system-wide congestion costs; (2) data on system conditions, such as transfer capability and planned and forced outages; (3) information on other prices, such as fuel prices and prices in adjacent markets; (4) information on load served from the spot market; (5) data relating to generator bidding patterns; and (6) information on Congestion Revenue Rights.

448. In addition, monitors must have the ability to obtain data on generator production and opportunity costs and information on the operating status of transmission and generation facilities that relate to claimed outages or deratings. Generator-specific data on all relevant costs and operating parameters—*e.g.*, start-up, no-load, environmental, fuel, maintenance, ramp rates, low and high operating levels, and heat rates—may also be relevant to establishing appropriate bid caps for participating generator agreements. These data when combined with information acquired in the normal course of business operations and schedules for planned outages should give monitors the information they need to fully analyze the competitiveness of the markets operated by the Independent Transmission Provider.

449. As a condition for participating in the spot markets, and using the transmission grid, market participants must agree to provide the market monitor with any information requested. Since the ability of the market monitor to perform his or her monitoring role is dependent upon the ability to acquire the necessary information, the monitor must have the ability to require market participants to provide information. This is an important enforcement tool. The Independent Transmission Provider's tariff should specify the penalties that would apply to market participants who fail to comply with an information request from the market monitor. Market participant objections to market monitor information requests will be resolved by the Commission on an expedited basis because delays in providing information could result in continuing harm to the market. In any such dispute the Commission will give substantial deference to the market monitor's stated need for the information.

450. All information obtained by the monitor that is specific to a market participant would be treated confidentially. Any disputes concerning how the confidential information could be used would be resolved by the Commission, before the data are released to the public. Since the Commission has oversight responsibility for wholesale electric markets, any data collected by the market monitor would be available to the Commission and the confidentiality of the data would be protected by the Commission under its regulations.

c. Reporting Requirements

451. At a minimum, the monitor would be required to submit an annual report to the Commission and the Independent Transmission Provider's governing board, and share that report with the Regional State Advisory Committee. The report would include: (1) A general description of the market operations, supply and demand, and market prices; (2) an analysis of market structure and participant behavior following guidelines described above; (3) an evaluation of the effectiveness of mitigation measures taken; (4) an overall assessment of market efficiency perhaps using a simulated competitive benchmark as some have developed; (5) an evaluation of barriers to entry for generating, demand-side, and transmission resources; and (6) any recommended changes to market design or market power mitigation measures to improve market performance. The report would also include a discussion and analysis of any region-specific issues that the monitor judges important to achieving a competitive outcome. This could also be particularly useful to the planning process in determining where expanded transmission capacity might reduce market power problems in load pockets. The annual report would be made public, with appropriate protections to maintain confidentiality, if necessary.

452. In addition, the market monitor will be required to report to the Commission, through the Office of Market Oversight and Investigation, any instances of conduct by market participants that appear to be inconsistent with the Independent Transmission Provider's tariff. Early reporting of questionable conduct will permit coordination between the market monitor and the Commission's investigative staff to determine the best methods for developing the facts and addressing conduct that could be harmful to the market.

453. The Commission requests comment whether additional reporting requirements are needed.

d. Enforcement of the Tariff Rules

454. The market monitor must play an important role in the enforcement of the market rules contained in the Independent Transmission Provider's tariff. In this role the market monitor will need to coordinate closely with the Commission's investigative and enforcement staff. However, to ensure effective enforcement, the market monitor must have adequate authority to investigate market participant conduct and the Independent Transmission Provider must have a set of predetermined penalties to apply to conduct that is in violation of the rules of the Independent Transmission Provider's tariff.

455. As a condition of participating in the markets operated by the Independent Transmission Provider and using the transmission grid operated by the Independent Transmission Provider, the Commission proposes to require market participants and transmission customers to agree to predetermined penalties that would apply to violations

of the tariff rules. Since the tariff rules are intended to ensure the fair and efficient operation of the markets, the penalties should be designed to deter conduct that is inconsistent with the fair and efficient operation of the markets. Specifically, the penalties should deter conduct that results in an economic benefit derived from a violation of the rules. The penalties should, at a minimum, require payment of the economic benefit derived by the violator from violating the rules. Where the violation could result in conduct that could be harmful to the reliability of the grid, it would be appropriate for the penalty to be significantly higher to serve as a deterrent for the conduct. The Independent Transmission Provider's tariff must specify the conditions that would apply for each level of penalty.

456. It may be appropriate to build into the tariff standards for mitigating the penalty. Some standards that could be used are: the impact on the operation of the grid, the financial impact on the violator, and any good faith efforts to maintain compliance. The Commission requests comment on the conditions that would justify mitigation of the penalty.

J. Long-Term Resource Adequacy

457. To operate the transmission system reliably, the transmission operator must be able to balance generation and load at all times. This requires adequate electric generating, transmission, and demand response infrastructure. Some lead time is needed to develop adequate infrastructure for the future through self supply or bilateral contracting.

458. Resource adequacy today must be assessed at the regional level. Because all customers in an interconnected region are interdependent, a shortage of resources for some customers in the region can lead to a shortage for the entire region, which threatens reliable grid operations and risks sustained shortages with attendant high prices for the region.

459. We propose a resource adequacy requirement to provide for sufficient supply and demand resources to avert such shortages. Under these procedures, we believe that involuntary curtailment will rarely if ever be employed. However, consistent with current policies, the proposal must include procedures for such emergency conditions.

1. The Reason for the Requirement

460. The Commission proposes to adopt a resource adequacy requirement to help ensure development of the infrastructure needed for reliable transmission system operation. Because electricity cannot be generated and easily stored for future delivery, extra generating and demand response resources are needed to serve a function similar to storage in the natural gas industry; other commodity markets would call these a supply inventory. The cost of necessary reserves is analogous to the necessary cost of storage or inventory.

461. A requirement to assure adequate long-term resources is currently needed because spot market prices do not consistently signal the need for new infrastructure in the electric power industry. Most resources take years to develop and spot market prices alone may not signal the need to begin development of new resources in time to avert a shortage. Moreover, spot market prices that are subject to mitigation measures may not produce an adequate level of infrastructure investment even after a shortage occurs. Further, as long as regional resources are made available to all regional load-serving entities and their customers during a shortage, such entities have the incentive to lower their supply costs by depending on the resource development investments of others, a strategy that leads to systematic under-investment in infrastructure by all load-serving entities in the region.[217]

a. Spot Market Prices Alone Will Not Signal the Need To Begin Development of New Resources in Time to Avert a Shortage

462. The spot market price does not yet work well to produce long-term reliability investment, even without price mitigation, for several reasons. Extra resources need to be planned in advance for electricity because, when prices rise, demand is not reduced quickly and new generation cannot be added quickly. Both the demand for electricity and the supply of new generating capacity generally respond very slowly to price.

463. Regarding demand response, most retail customers buy power at a regulated fixed price. Even in states that have approved retail competition, customers are often shielded for years from price changes by a rate freeze. They are unaware of hourly changes in the cost of producing electricity. Electric meters are read monthly, and customers see only the imperfect price signal of a monthly bill rendered after electricity is used. Although larger commercial and industrial customers can be more price responsive, for many of them electricity is a small fraction of their cost of doing business and may receive little managerial attention. It takes time to develop the administrative rules and the technical capability to reduce consumption. As a result, most demand today is unable to respond to real-time prices because of insufficient price information, inflexible rate designs, and metering limitations.

464. The response of new generating capacity to price is slow because it takes time to plan, site and construct new electric power generating facilities. Development of a new power plant takes two to five years or more, depending on the type of plant and its location. It can take even longer to site the transmission lines needed to transmit the power to customers.

465. These factors together can lead to sustained periods of inadequate supplies, threatening the reliable operation of the bulk power system. Insufficient demand response to price and the slow supply response to price can combine to produce electricity shortages that not only threaten reliability but also can raise day-ahead and real-time market prices significantly.

466. Further, rushing to relieve inadequate regional supplies and reduce high regional spot prices may bias construction choices toward supply resources that can be constructed quickly, perhaps sacrificing long-term cost minimization, environmental concerns and fuel diversity goals. Most customers prefer spreading out resource capital costs over time to concentrating them into a peak period. A resource adequacy requirement accomplishes this.

b. Spot Market Prices That Are Subject to Mitigation Measures May Not Produce an Adequate Level of Investment When a Shortage Occurs

467. Customers object strongly to inadequate supplies—and high prices when supplies are inadequate—because electricity is essential for many uses and customers cannot turn to substitutes to reduce electricity demand. Electric power drives modern life, and there is significant societal disruption from even short supply interruptions.

468. For these reasons, customers want protection from the exercise of market power that may occur when supplies are short, and some form of market power mitigation is needed under these circumstances, as discussed in the market power mitigation section. However, market power mitigation may tend to suppress the scarcity price that

[117] For further discussion of these topics, *see e.g.,* Steven Stoft, *Power System Economics* (IEEE Press, Wiley-Interscience, 2002) especially ''Fallacy: The 'Market' Will Provide Adequate Reliability.''

would otherwise stimulate new resource development. As a result, investors may not develop adequate infrastructure—making the problem worse—unless there is a provision for resource adequacy. Such a provision helps customers by assuring adequate supplies and helps generation developers by creating a demand for resources in advance of electricity prices doing so alone.

c. Load-serving Entities Will Underinvest in Resources Needed for Reliability if They Can Depend on the Resource Development Investments of Others

469. In an interconnected region, the failure of some market participants to secure sufficient long-term electricity resources can contribute to a shortage that affects reliability and spot market prices for all participants in the wholesale power market.

470. Under retail competition, load-serving entities competing for customers may compete on the basis of cutting the cost of forward contracting for resources unless they all are held to the same resource adequacy requirement. Without such a uniform requirement, those suppliers that contract for reserves may lose market share, and those who do not may gain a market share—at least for a short period of time. For this reason, a load-serving entity has an incentive to minimize its own costs by procuring few or no reserves and relying on others to develop reserves. If the rules allow it, some load-serving entities will try to have the reliability benefit of adequate regional resources that other load-serving entities pay for or that uncontracted-for generation must offer pursuant to market power mitigation.

471. Severe power shortages lead to public insistence on government intervention. Both historical practice and recent events indicate that during a shortage those load-serving entities that have reserves are required by government to share them with those that do not have reserves. There are at times state regulatory and gubernatorial requirements to protect customers from blackouts or high prices, a U.S. Department of Energy requirement for utilities to share power reserves in an emergency, or a Commission requirement to bid all available power into an organized spot market.

472. Some market participants depend on government intervention during severe shortages as an alternative to paying their share of the cost of developing adequate regional resources. As long as regional reserves are made available to all, a load-serving entity can reduce its own reserve resource costs and rely on the resources of others. The result is that all load-serving entities will tend to follow this strategy, leading to a systematic underinvestment in resources needed for reliability.[218] The current physical configuration of the transmission grid often exacerbates this problem because it is often difficult to impose the results of one party's resource shortfall solely on that party. For example, if several competing load-serving entities serve customers in the same electrical neighborhood, it may not be technically feasible to curtail some of these customers and not others during a shortage.

473. These arguments persuade us to propose a long-term resource adequacy requirement in the Standard Market Design rule. A resource adequacy requirement provides for timely development of supply and demand response resources to assure regional resource adequacy. It helps smooths out the price swings of the electricity business cycle. A well-designed resource adequacy requirement supports competitive markets if it allows suppliers to compete to provide infrastructure and buyers to choose the infrastructure with the best combination of features such as cost, reliability, environmental effects, and service life.

2. Basic Features of the Requirement

474. We propose to require, as set out in the proposed regulations, that an Independent Transmission Provider must forecast the future demand for its area, facilitate determination of an adequate level of future regional resources by a Regional State Advisory Committee, and assign each load-serving entity in its area a share of the needed future resources based on the ratio of its load to the regional load.

475. The Independent Transmission Provider must assure that each load-serving entity in its area acts to meet its share of the future regional needs—through self-supply, contracts to purchase generation, biddable demand or other demand response program. The Independent Transmission Provider must apply standards, discussed below, to audit the adequacy of the plans of load-serving entities to meet the future resource needs of its area. Moreover, the Independent Transmission Provider must check that resources are not double-counted by different load-serving entities. In a region with more than one Independent Transmission Provider, each Independent Transmission Provider must coordinate this checking responsibility with all the Independent Transmission Providers in the region.

476. If a power shortage occurs during which the Independent Transmission Provider is unable to satisfy demand in the spot market and also meet its reliability requirement for a minimum level of operating reserves, the Independent Transmission Provider must add a per-megawatt-hour penalty during the shortage to the price of energy taken from the spot market by a load-serving entity that did not meet its share of the regional needs for that year.

477. Further, if the operating reserve level decreases to the point that the Independent Transmission Provider must curtail load, the Independent Transmission Provider must, to the extent possible, curtail the spot energy purchases of the load-serving entity that did not meet its resource adequacy requirement before curtailing the spot energy purchases of load-serving entities that did. The load-serving entity is subject to such first curtailment during a shortage only in the amount by which it falls short of meeting its share of the resource adequacy requirement for the year in which the shortage occurs.[219]

478. If a shortage remains after all such first curtailments are completed and additional curtailment is necessary, the remaining loads of the first-curtailed load-serving entities and the loads of other load-serving entities that have satisfied their resource adequacy requirement would be curtailed under the same protocol. In this case the shortage may be attributable to certain load-serving entities of either type that, whether or not they may have met their resource adequacy requirement. We expect that those load-serving entities that are short of their own reserves would lose service ahead of those that are not short.

479. The approach to resource adequacy proposed here is intended to assure the development of both new supply and demand response resources.

[218] This is the well-known ''free rider'' problem for public goods, those for which consumption cannot be limited to those who paid for them (such as parks and national defense) and that are available to all users even if only some users pay for them. *See, e.g.,* Lee S. Friedman, *The Microeconomic of Public Policy Analysis,* Princeton University Press (Princeton, NJ 2002), which states at pages 597–598:

> If their provision were left to the marketplace, public goods would be underallocated. The reason is that individuals would have incentives to understate their own preferences in order to avoid paying and free-ride on the demands of others. Thus, public goods provide one of the strongest arguments for government intervention in the marketplace: not only does the market fail, but it can fail miserably.

[219] A load-serving entity that continues to take spot market energy despite the curtailment order of the Independent Transmission Provider would be subject to a very high penalty under the tariff.

This approach focuses on encouraging payment to fund construction of future resources instead of avoiding payment of a penalty for inadequate current resources as in some current programs. The forward-looking planning horizon provides time for market entry by new suppliers, which will help to check any market power among existing suppliers.[220]

480. This proposal is designed to complement, not replace, existing state resource adequacy programs. A vertically integrated utility satisfying a current state resource requirement that equals or exceeds its share of the resource adequacy requirement would not have to do anything more. For those states that have retail choice programs in which retail customers or their suppliers buy power from a multistate region, we intend this approach to provide for regional adequacy in a way that no one state alone may be able to accomplish.

481. The proposed approach is like the traditional reserve margin requirement imposed by states on monopoly utilities. It worked well during most of the last century to ensure adequate supplies, and is still in use in most states, especially states that have no retail choice program. However, because the traditional approach relies on individual utility plans and resources, it might not continue to work well in a region where utilities now rely on independent power producers in several states for new resources instead of their own new generation. The traditional reserve margin requirement may also not work well in a region where some states have traditional monopoly utilities and others have retail choice because a shortages in one state can affect all states in the region.

482. To continue to rely on the traditional reserve margin requirement, it has to be adapted to have a regional focus and to fit with competitive procurement. We propose a resource adequacy requirement of this type.

483. The resource adequacy requirement proposed here is unlike that of the three Northeast ISOs. ISO-New England, the New York ISO and PJM each impose an obligation on load-serving entities known as an Installed Capacity (ICAP) requirement. The three requirements differ, but share some basic characteristics. We are reluctant to impose a national ICAP requirement, in part because of our concern about the effectiveness of the existing ICAP programs and in part because they were based on former voluntary tight power pools. The three ISOs play a strong role in administering the program, a role that may not suit regions without a history of tightly coordinated reserve sharing.

484. The basic features of the proposed requirement are set out next, including discussion of the demand forecast, the level of resource adequacy, the role of the load-serving entity, the load-serving entity's share of the regional resource adequacy requirement, the types of resources that can satisfy the resource requirement, the standards that each type of resource must meet, the planning horizon, enforcement of the requirement, and regional flexibility.

a. Demand Forecast

485. An Independent Transmission Provider would be required to do an annual demand forecast for its area. The forecast would look ahead for the time period needed to add new supply and demand response resources. We will refer to this time period as the planning horizon, a topic discussed further below.

486. Demand forecasts have long been used in the utility industry to determine the need for future resources and to plan new infrastructure investments. The Independent Transmission Provider may undertake a ''bottom up'' method of demand forecasting by adding up the demand forecasts of its component areas where they can be relied on.[221] This may be accomplished through a collaborative process with all stakeholders.

b. Level of Resource Adequacy

487. After the area's demand is forecast, the Independent Transmission Provider must assess whether the collective resource plans of load-serving entities in this area are adequate to meet the projected future peak need with allowance for adequate reserves. In today's more competitive environment, the effectiveness of single-utility supply forecasts may be reduced. Under open wholesale transmission access, regional patterns of energy flow can change quickly, making single-utility transmission planning difficult. Generators sited in a utility's service territory, if not under contract, may export power to another area or region. Single-utility forecasting is also more difficult today because power market information is considered very sensitive. Competitive suppliers are reluctant to share this information with a utility that is a potential competitor. A regional assessment of regional supply adequacy by one or more independent entities in the region would help overcome these difficulties.

488. Further, close coordination is needed between those planning generation and transmission because the location of planned generation affects the location of planned transmission and vice versa, and an Independent Transmission Provider (or a group of Independent Transmission Providers acting collectively in a region with more than one Independent Transmission Provider) is in the best position to coordinate these planning functions.

489. Once the future level of supply and demand resources is determined, the region must assess whether this level is adequate. This requires a regional determination of the appropriate level of resource reserves, for example, whether the reserve margin (if reserve margin is the region's measure of resource adequacy) should be 12, 15, 18 percent, or another level. We seek comment on and encourage regional discussion of appropriate planning targets in energy-limited areas, specifically on how to incorporate volatility of annual hydropower supply.

490. Each region should take its own characteristics into account when determining the appropriate level, subject to a minimum level of resource adequacy for all regions discussed below. This determination has been made by load-serving entities under the oversight of the states, and we want this state oversight to continue. We propose that the level should be set by a Regional State Advisory Committee.[222] States in the region should have this strong role in determining the level of resource adequacy because a higher level provides greater reliability and also incurs higher costs that affect most retail customers. State representatives are in the best position to determine on behalf of retail customers the trade-off between the cost to the customers of extra generation and demand response reserves and the difficult-to-quantify benefits to the customers of increased reliability and reduced exposure of the region to the effects of a power shortage.

491. We will require the Independent Transmission Provider (or the several

[220] A regional resource adequacy requirement should also provide substantial evidence of need for infrastructure to investors as well as to siting authorities. This should aid suppliers in acquiring financing and should facilitate siting decisions. An added benefit may be the ability to better predict, plan, and finance new transmission system facilities associated with these resource requirements.

[221] A load-serving entity has an incentive to underestimate its future load if doing so would reduce its share of the resource adequacy requirement. For an analysis of bias in demand forecasts, see Mark Bock, ''Analysts hunt for bias in NERC forecasts,'' *Electric Light & Power*, July 2002.

[222] *See* the following section, State Participation in RTO Operations, for a discussion of the composition of the advisory committee.

Independent Transmission Providers in a region with more than one such Provider) to provide a forum and assistance to the Regional State Advisory Committee to establish the appropriate level of resource adequacy for the region. Because many Independent Transmission Providers encompass more than one state (or province), the Independent Transmission Provider's role as a facilitator will be helpful in establishing the regional reserve level.

492. However, we ask for comment on what fallback provision should be employed if the Regional State Advisory Committee does not reach agreement on the appropriate level of resource adequacy. We believe that having different reserve levels in different states in the same region maintains the problem of some customers relying on the reserves of others.

493. We are concerned that the requirement be set so that the Independent Transmission Provider can operate the interstate transmission system reliably with real-time operational resource adequacy. We are also concerned that inadequate resources could lead to poor market liquidity and even shortages with sustained high wholesale power prices. For these reasons, we propose to adopt a 12 percent reserve margin[223] as a minimum regional reserve margin for all regions with the understanding that this is low by traditional generation adequacy standards and that the Regional State Advisory Committee in each region may set this number higher for the region to achieve greater reliability. We selected a 12 percent reserve margin as a minimum in that it is two-thirds of the typical historical reserve margin target of 18 percent for large utilities.[224] We emphasize that most utilities historically used a reserve margin well above 12 percent. This 12 percent reserve margin is intended to be a safety-net level in planning for reliable future transmission and market operations and not to be the target reserve level for the region that should be established by the Regional State Advisory Committee.

c. Load-serving Entities

494. Each load-serving entity must satisfy a portion of the regional resource adequacy requirement. Load-serving entity here means any entity that uses transmission in interstate commerce to provide power to load, whether a traditional distribution utility or an energy service supplier that aggregates retail loads under a retail access program.

495. A large retail industrial or commercial customer that has retail access rights and buys power directly from suppliers is also considered a load-serving entity. If it does not buy power from another load-serving entity but uses the interstate grid to buy power directly from a supplier, it too would be required to meet its share of the resource adequacy requirement. As for other load-serving entities, their reserves may include the ability to reduce their own demand on the grid.

496. A load-serving entity may choose a higher level of reliability by developing more supply or demand response resources than required. Further, a load-serving entity may choose greater reliability and price assurance by procuring additional reserves for its own use. In particular, customers in a load pocket that is served by a few large generating units may need a higher reserve margin to have the same level of reliability as customers outside a load pocket.

d. Load-Serving Entity's Share of the Regional Resource Requirement

497. Once the future regional requirement is determined, each load-serving entity's share of the regional requirement must be determined. Meeting a regional resource adequacy level does not assure that every part of the region has adequate resources if there are internal transmission constraints or if resources are counted that may be sold outside the region, retired before needed, or otherwise made unavailable. For these reasons, it is important that resources not be considered merely regional but be associated with and committed to particular load-serving entities.

498. We request comment on two methods for determining each load-serving entity's share of the regional requirement. One is to allocate the future resource adequacy needs to loads based on each load's forecasted future demand. For example, if the load forecast is for three years ahead and a particular load is growing faster than the regional average, its share of the adequacy requirement could be based on its forecast load ratio share for three years ahead, not on the present load ratio share. This method assigns more adequacy responsibility—and cost—to faster growing loads. However, if the Independent Transmission Provider's forecast is made through a ''bottom up'' method that adds up individual load forecasts, it must rely on each load to report its growth rate accurately. This approach creates an incentive for loads to understate their growth to lower their resource costs.

499. The other method is to allocate the future adequacy requirement to loads based on each load's most recently documented load ratio share. This method is less subject to manipulation. However, an area with a slow load growth located within a region of generally high load growth may subsidize the high reserve needs of its neighbors.

500. We ask for comment on which of these two methods the Commission should choose in the Final Rule. Alternatively, we ask whether this issue should be left to regional determination.

501. Once each load-serving entity's share of the regional adequacy requirement is determined, the Independent Transmission Provider must inform each load-serving entity of its share. It must require each load-serving entity to report and document how it plans to meet its adequacy requirement.

502. The time available to the load-serving entity from being informed of its resource share to having to report to the Independent Transmission Provider must be adequate to allow it to develop arrangements for meeting future resource needs. We ask for comment on how much time is needed for these purposes.

e. Resources That Can Satisfy the Resource Needs

503. Each region's resource adequacy requirement could be satisfied by a combination of generation,

[223] The reserve for a period is the amount of resources expected to be available during the period less the forecast peak load during the period. The reserve margin is the ratio of the reserves to the forecast peak load during the period, expressed as a percentage. A region may use another measure of adequacy as long as the minimum level is the arithmetic equivalent of a 12 percent reserve margin. For example, many use capacity margin, which is the ratio of the reserves to the amount of resources expected to be available during the period, expressed as a percentage. A capacity margin of 10.7 percent is the same as a reserve margin of 12 percent. Some may measure adequacy with a loss-of-load probability, called LOLP, which is a statistical measure of the expected total time during a period that generation will be unable to meet load. The common U.S. standard is one day in ten years, which means that the sum of the hours (or fractions of hours) during a ten-year period when generation is expected to be short is 24 hours. Reserve margin cannot be translated directly into LOLP without studying a particular system. For example, an area served by a few large generators is more vulnerable to a shortage caused by an outage of one or two large generators than a similar area served by many smaller generators. The area with a few large generators may need a larger reserve margin to achieve the same LOLP. A general rule-of-thumb for a large U.S. utility system is that an LOLP of one-day-in-ten-years is achieved with a reserve margin of about 18 percent.

[224] The target level of these reserves, often called planning reserves, is not the same as the operating reserve level, a subject treated further below.

transmission, and demand response infrastructure.

(1) Generation and Transmission

504. The supply requirement could be satisfied by self-owned generation, local distributed generation, or firm bilateral contracts for power that are backed by specific generating units (or a portfolio of designated generation units). The firm bilateral contract could be either a forward contract for the purchase of power or an option to purchase energy under specified shortage or price conditions, as long as the firm contract is backed by specified generating units.

505. In any of these cases, the generator must be committed to supply power to the load-serving entity, at least under certain conditions. Self-owned generation that is committed to another load-serving entity, unless it can be recalled during a shortage, would contribute to the other load-serving entity's requirement, not the requirement of the load-serving entity that owns it. Generation under contract must specify that the generator will be available to the load-serving entity—or at least to the market that the load-serving entity participates in—under conditions set out in the contract. These conditions, discussed further below under generation standards, must be adequate to meet the region's need for reserve resources.

506. The firm contract would be for a forward-looking period that would at least cover the planning horizon, which (as discussed further below) would be selected regionally and should be based on the time needed to develop new resources in the region. The load-serving entities must also demonstrate that future use of the designated resources is physically feasible and, in particular, that transmission is or will be available to deliver energy from a generator to the load-serving entity that claims it in its resource plan.

(2) Demand Response

507. Allowing demand response infrastructure to satisfy the requirement removes bias toward exclusive reliance on new generation to meet regional needs. Better demand response to high prices when a shortage condition approaches will lower demand and reduce the use of high-cost power resources. Demand response will help ensure reliability, prevent a shortage that could produce a curtailment, act as a check against market power, and provide a yardstick for the value that buyers place on supply.

508. Biddable and interruptible load can satisfy the resource adequacy requirement as well as generation.[225] A load-serving entity that does not want to pay for generating reserves can substitute a demand response alternative to meet its resource adequacy requirement. Under some state programs, the larger retail customer may be rewarded for reducing its electric use in addition to enjoying a reduced bill for reduced consumption. Several states have this type of biddable load reduction; it is one way to allow the customer to determine how much it is willing to pay for power. Further, competitive energy service suppliers can compete for load by offering lower rates to customers who agree to participate in demand response programs such as remote air conditioner cycling, aggregate building load management, and other proven demand response and load management options.

3. Resource Standards

509. The Independent Transmission Provider must determine if each load-serving entity's planned resources meet certain standards. The resources must meet the standards to count toward satisfying the entity's share of the regional resource requirement. Both generation and interruptible or biddable load must meet standards to satisfy the requirement.

510. We propose here certain minimum standards for comment. We also are considering in the Final Rule to ask the North American Energy Standards Board (NAESB) to develop more detailed standards for determining whether resources satisfy the resource adequacy requirement, and we seek comments on this approach.

a. Generation Standards

511. Generation must be owned by or under contract to the load-serving entity and committed to meet the resource needs of the load-serving entity at least during certain conditions such as an operating reserve shortage. The Independent Transmission Provider must be satisfied that the generation is physically feasible; that is, the generating units are capable of generating the power planned, and enough transmission is available to deliver the power from the generating station to the particular load. The generating units under contract must be real and specific generators. This is so that only real generation that can avert a supply shortage is counted and so that its transmission over the grid can be assured. For example, it does no good for a load on Long Island to claim a generator in western New York as a resource if the power cannot be delivered to Long Island during a Long Island shortage.

512. Because the purpose of this requirement is to encourage the development of new resources including new generation, generation under contract for development within the planning horizon should satisfy the requirement. Should the Commission specify the contract content needed to rely on generation under development? If so, should we refer this matter to NAESB to determine the content?

513. For these reasons also, a contract with a marketer to deliver power at a future time from unspecified sources cannot satisfy the requirement. The purpose here is not to transfer financial risk for nonperformance to a marketer but to ensure performance, that is, to ensure that enough actual, deliverable generating capacity is available or developed at satisfactory locations to avert a future shortage. However, a forward contract with a marketer that is linked to specific generation and demonstrates transmission adequacy would satisfy the requirement. We ask for comment on whether we should allow a liquidated damages contract for power from unspecified sources to be included in the resource adequacy plan, and also on whether we should allow a load-serving entity that initially fails to satisfy the resource adequacy contract, but later brings in new resources under a liquidated damages contract for the amount of its resource deficiency, to avoid the penalty price and first curtailment in the spot market during a shortage.

b. Transmission Standards

514. Generation must be deliverable to satisfy the requirement. A Congestion Revenue Right for the appropriate year is one way to satisfy this requirement. We propose to adopt a practice (used in PJM) that allows a resource owner to pay for the development of adequate transmission to deliver its energy to a load and then to sell its Congestion Revenue Rights while still satisfying the requirement that its generation be deliverable. Should a commitment by any load-serving entity to pay congestion costs no matter how high also satisfy the requirement? If so, how should the Independent Transmission Provider respond if the sum total of all such commitments exceeds the available capacity of a bottleneck interface?

515. A robust transmission system with few constraints may allow a load to rely on generation and demand

[225] The traditional reliability reserve margin allows interruptible load to be counted equally with generation resources, with some exceptions.

response reserves that are farther away than if the transmission system is weak. Supply reserves that are not deliverable to the load claiming them when needed cannot be counted as satisfying that load's reserve requirement.

516. For transmission as well as for generation and demand response, the purpose of this requirement is to encourage the development of least-cost resources, which may include new transmission needed to access existing or new generation. We believe therefore that planned transmission with full siting approval and completion expected within the planning horizon should satisfy the adequacy requirement.

c. Demand Response Standards

517. Demand response must also be verifiable to satisfy the adequacy requirement. The Independent Transmission Provider must have confidence that the demand response resource will be able to contribute when called on during a shortage. Demand response may be obtained through biddable demand reduction, interruptible load, or other dependable load management program. Distributed generation that is interconnected with a customer, a load-serving entity, or an energy services company, although it is technically generation and not demand response, can also be used by a local distributor to reduce the demand that the distribution system places on the grid. With biddable demand reduction, certain loads will be assured of dropping off the system at known price levels; the amount of load dropped should increase with the price.

518. With interruptible load, a customer pays a lower power price year round but will be interrupted under defined shortage conditions; the load is subject to a simple on-off criterion. An important feature of this proposal is that the load-serving entity plan that depends on interruptible load to meet its resource adequacy requirement must be capable of being implemented. The Independent Transmission Provider may require, for example, that the load-serving entity install equipment that gives it direct control over the loads of the customers that are subject to the interruption. We recognize, however, that installation of such equipment may be too costly or otherwise impractical in some situations. In that case, the load-serving entity must have a satisfactory arrangement for implementing its interruptible load program under the instructions of the Independent Transmission Provider.

519. If load in an area "buys" demand reduction from another area (in effect buying some of that other area's freed-up generation), the transmission needed to deliver the freed-up generation to the load that relies on it must be available.

4. Planning Horizon

520. The purpose of a forward-looking resource adequacy requirement is to create a demand for new resource entry in advance of a shortage so that enough supply construction and demand response infrastructure installation are begun in time to avert the shortage. The planning horizon for each region is the number of years ahead for which the Independent Transmission Provider must forecast annually its area's load, as well as the number of years ahead for which load-serving entities must show that they have adequate resources. For example, the Independent Transmission Provider could forecast its area's peak load three years from the present and require that each load-serving entity in its area have acceptable plans today to have enough resources three years from now to meet the forecast peak with a reserve margin of 12 percent. In this example, the planning horizon is three years and the reserve level is the minimum 12 percent.

521. The choice of the planning horizon affects the lead time for construction and the duration of forward contracts that can satisfy a resource adequacy requirement.[226] The traditional state-required electric company planning horizon was 10 to 20 years. The horizons were established when the industry relied on new large hydroelectric, coal, or nuclear facilities to meet growing load, and these facilities could take 10 or more years to site and construct. Today, most new resources are planned and developed over a much shorter time frame, in part because of the reliance on low cost natural gas. However, this planning horizon could change again if natural gas were no longer the main fuel of choice.

522. Because the planning horizon should be no less than the time frame for developing new resources and development times vary from region to region, the planning horizon can depend on that region's reliance on coal, gas, wind, hydropower or new demand-response technology for new supply. This argues for allowing each region to determine its own appropriate planning horizon.

[226] For example, forward-contracting for supply with one-year contracts that begin today and end after one year would not satisfy an adequacy requirement with a three-year planning horizon. A one-year contract for the third year forward would satisfy the goal for that year.

523. We propose to make the planning horizon a matter for regional choice. Regions should consider several factors in selecting the planning horizon. Most important, the planning horizon chosen should not be so short that it fails to motivate and achieve construction of generation and demand response resources in time to avert a shortage. Greater fuel diversity may be achieved with a longer planning horizon. If the horizon is short, two years for example, load-serving entities may have an incentive to select resources that can be developed in two years or less, such as peaking units and some other gas-fired generators. A longer planning horizon allows time for development of other resources such as coal-fired generation, hydroelectric resources, and some advanced demand response programs. Load-serving entities in retail choice states would benefit from a shorter planning horizon because it would reduce their business risk associated with demand forecast error. Also, they may not want to enter into bilateral contracts for supplies for a time period that is longer than the duration of their contracts with their customers.

524. We propose to have the Regional State Advisory Committee determine the planning horizon for the region. The Independent Transmission Provider (including each Independent Transmission Provider in a region with more than one Independent Transmission Provider) must provide information and support to the Committee, as requested, to help it to determine the region's planning horizon. We request comment on how to resolve any lack of consensus within the Committee regarding the appropriate planning horizon. We also ask for comment on whether the Commission should establish limits on the region's choice of planning horizon, such as at least three years and no more than five years.

525. We also ask for comment on whether to have a resource adequacy requirement before the end of the first planning horizon period. For example, if the horizon is three years, should there be a requirement for resource adequacy in the first two years?

5. Enforcement

526. Here we explain in more detail our proposal to enforce the resource adequacy requirement, along with some alternative enforcement procedures, and ask for comment on the most effective enforcement method.

527. Unlike some ICAP requirements, the approach adopted here does not require a load-serving entity to pay a penalty in the near term for failure to

have adequate future resources. Our proposed approach relies primarily on two enforcement mechanisms: (1) a Commission-set tariff penalty imposed on a load-serving entity that threatens reliable transmission operation by taking energy from the spot market during a shortage in a year for which it fails to meet its resource adequacy requirement, and (2) a Commission requirement that the spot market electric service of such a load-serving entity must be curtailed first when the shortage that is severe enough to require that some customers be curtailed. Each of these mechanisms, the penalty rate and the load curtailment, would occur at the end of the planning horizon, not the beginning.[227]

528. The first mechanism applies during a power shortage in which the Independent Transmission Provider is unable to satisfy demand in the spot market and also meet its reliability requirement for a minimum level of operating reserves.[228] As a shortage develops, price is expected to increase in the spot energy market. A load-serving entity that is short on self-generation, bilateral contracts (including affiliate generation and call contracts), and demand response resources will be dependent on the spot markets to meet its resource needs. The rising price in the spot market is, of course, a principal incentive for the load-serving entity to develop adequate supply and demand resources. If shortage conditions develop to the point where the Independent Transmission Provider cannot serve all load and maintain the minimum level of operating reserves, it must take some action to maintain reliable operation. Some load must be given either an economic incentive to exit the spot market or an order to stop taking power from the spot market. We propose that these measures be applied first to the load of the load-serving entities that did not meet their share of the resource adequacy requirement. However, the load-serving entity is subject to a penalty and first curtailment during a shortage only for spot energy purchases [229] and only in the amount by which it falls short of meeting its resource adequacy requirement.

529. Specifically, we propose that during such a shortage the Independent Transmission Provider must add a per-megawatt-hour penalty price to the price of energy taken from the spot market by a load-serving entity that did not meet its share of the regional needs for that year. This rate would apply only to spot energy purchases, not to power received from the load-serving entity's self-generation or bilaterally contracted energy. However, it would apply to spot market energy sales needed to correct for imbalances associated with energy from these sources. We would set the penalty price high enough that we do not suggest that failing to meet a resource adequacy requirement and paying a penalty rate is an acceptable alternative to developing new resources, which would be the case if the paying the penalty appears to be less costly over time.

530. The penalty price would increase in stages as the shortage becomes more severe. For example, the penalty price could be $500 (in addition to the spot market energy price) when operating reserves are just below the minimum level, $600 when operating reserves are more than below 1 percent below the minimum level, $700 when operating reserves are more than 2 percent below the minimum level, and so on. We ask for comment on having such a graduated penalty and the appropriate penalty rates.

531. This first enforcement mechanism provides a price-based mechanism to enforce a resource adequacy requirement and to restore the transmission system to a reliable condition. Most system operators—and their regulators—treat load curtailment (voltage reductions and blackouts) as a last resort measure, and operators may violate the reliability rule for minimum operating reserves rather than implement a load curtailment to satisfy the minimum operating reserve criterion.[230] We believe that the penalty price should be set high enough to bring about voluntary load reduction by a load-serving entity and thus restore the system to a reliable condition.

532. The second enforcement mechanism is applied when the operating reserve level decreases to the point that some load must be curtailed.[231] The spot energy purchases of that load-serving entity load would be reduced by the amount of its resource deficiency and consequently some of its customers would be curtailed before the loads of other load-serving entities.[232]

533. In support of this second mechanism, we will require the Independent Transmission Provider to

[227] For example, if the planning horizon is three years, a demand forecast would be made in 2004 for the year 2007. The Independent Transmission Provider would assess the adequacy of resources for 2007 and allocate the resource adequacy requirement for 2007 among the load serving entities. The entities would submit to the Independent Transmission Provider in 2004 their plans to meet their share of the 2007 resource adequacy requirement. An entity fails to submit in 2004 a satisfactory resource plan for 2007 would not be subject to the penalty rate or be among the first curtailed during a shortage in 2004 but would be subject to the penalty rate and be among the first curtailed during a shortage in 2007. Next year, in 2005, the same process repeats: the Independent Transmission Provider would forecast demand in 2008, and so on.

[228] Operating reserves are generation and demand response resources needed to keep the system in balance, follow changes in load, and make up for a "contingency" such as the loss of the largest generating unit or of a major transmission line that delivers more power than any one generating unit. The North American Electric Reliability Council and the regional reliability councils set rules regarding the minimum operating reserves that must be maintained by the system operator for reliable operation. The rules are expressed in a formula so that the value of the minimum operating reserves changes during the day with load conditions and with the sources of supply. Typically, for a large utility, the minimum operating reserves are in the range of 5 to 8 percent of load, but this can vary significant with changing conditions. An operator that operates with less than minimum operating reserves threatens not only its own reliable operation but the reliability of its electrical neighbors.

[229] These actions apply to spot energy purchases onluy. In the event that the load-serving entity that failed to meet its share of the resource adequacy requirement has adequate supply and demand resources outside the spot market available to it at the time of the shortage, the Independent Transmission Provider would continue to provide transmission to support delivery of these resources. This proposal gives deference to the ownership and contractual right to use self-generation, bilateral contracts, and demend response resources, and it encourages the development of such resources during the planning horizon period by those entities that failed to plan adequately at the beginning. It also discourages contracting with unreliable resources to meet the resource adequacy requirement because each load-serving entity must actually rely on its resources to meet its resource needs.

[230] We will not overturn this practice by requiring curtailment of load immediately to restore the minimum operating reserve level. Some regions have a regional policy of taking action to reduce voltage or shed load only when operating reserves fall to some fraction, such as three-fourths or three-fifths, of the minimum operating reserve requirements of the reliability organizations.

[231] Regional practice will determine when load must be curtailed to maintain reliable operation. Operators may continue to follow their existing reliability practices: those that do not curtail service immediately when the operating reserve level goes below the minimum must impose the penalty price on resource-deficient load-serving entities. However, it is not our intent to require an operator to violate a reliability rule by providing service with a penalty price instead of enforcing its reliability rule through load curtailment. We believe that a high penalty price may result in the needed load reduction. Whenever the operator must curtail load to maintain reliability, it should do so. Our requirement goes to which load must be curtailed first when curtailment of load is necessary, not to when curtailment becomes necessary.

[232] An individual load-serving entity may run short of planned-for resources when its region is not experiencing a regionwide shortage, for example, because of a combination of high demand on its own system and unplanned outages of its own resources. In this case it is not required to be curtailed because that load-serving entity may procure additional supplies from the short-term or long-term bilateral market or from the spot market. Since the region is not short, others are likely to sell power, including perhaps a portion of their reserves on the basis that the reserves can be recalled if a regionwide shortage occurs.

inform the load-serving entity's state regulatory authority [233] if the load-serving entity fails to submit a satisfactory plan for adequate future resources, thereby exposing its customers to possible penalties and future first curtailment during a shortage. Our intent is to rely on the traditional state role of enforcing a load-serving entity's reserve obligation. We believe that in most cases the state regulatory authority would prefer to have the load-serving entity meet the adequacy requirement as a condition of doing business in the state, rather than expose its retail customers to first curtailment. The state regulatory authority may wish to consider any decision of a load-serving entity not meet its resource adequacy requirement. It may want to ask the load-serving entity to identify which of its customers will be subject to first curtailment if the region is short of power.[234]

534. If the Independent Transmission Provider does not have direct control of the circuit equipment needed to implement a curtailment and relies on the load-serving entity to follow its instructions to implement a curtailment, the load-serving entity would be subject to a severe penalty for the unauthorized taking of power from the spot energy market because this jeopardizes grid reliability. We propose to charge the applicable Locational Marginal Price plus $1000/MWh for all unauthorized energy taken following an instruction to implement curtailment.[235] We also seek comment on whether the $1000/MWh penalty would be sufficient to deter unauthorized taking of energy and, if these penalties are paid, who should receive these revenues.

535. We believe that load-serving entities, under these enforcement provisions and under the oversight of state regulatory authorities, will meet their resource adequacy requirement and not be subject to these curtailment penalty and first curtailment provisions at all. If most meet the requirement as we expect, shortages and first curtailment of any that do not should occur infrequently.

536. Having presented our enforcement proposal, we suggest variations of this proposal and ask for comments on these alternatives. As mentioned, under our proposal the penalty rate or load curtailment would occur at the end of the planning horizon, not the beginning. However, we ask for comment on this approach compared to an alternative approach that may provide a more immediate and effective incentive to a load-serving entity to take action to provide for future resources well in advance of facing a penalty or first curtailment. This is to impose a penalty on the load-serving entity immediately (that is, in year 2004 to continue the example in an earlier footnote) if it fails to submit a satisfactory plan to meet its 2007 resource adequacy requirement. We did not propose this option as our first choice because it has some of the unfavorable features of some ICAP programs that focus more on avoiding immediate penalties than on motivating long term resource development. However, we ask for comments on the merits of this alternative approach.

537. As presented, the Independent Transmission Provider audits the plan of each load-serving entity only at the beginning of the planning period (in 2004 in the example above). We are concerned that a load-serving entity may submit a satisfactory plan but fail to fully implement the plan. The proposal permits but does not require the Independent Transmission Provider to audit each year the progress of the load-serving entity in implementing its plan, and we ask whether we should explicitly require this. If the load-serving entity's progress is unsatisfactory, should the Independent Transmission Provider find that it fails to satisfy its resource adequacy requirement? If the load-serving entity implements its plan but some of its resources fail to perform when needed during a shortage, should that load-serving entity, in addition to having a greater need for spot market energy at a presumably higher spot market price, also be subject to either of the enforcement mechanisms set out above?

538. Another feature of our proposal is that it would not affect electric service from the self-generation and bilateral contracts of a load-serving entity that fails to meet its resource adequacy requirement (except that it would be subject to a penalty price during a shortage for balancing energy in the spot energy market). We ask for comment on whether this proposal unduly weakens the incentive to develop regional resources and whether, in the alternative, the Independent Transmission Provider should first curtail service to the load serving entities that failed to meet their share of the resource adequacy requirement, including transmission service from resources acquired outside the spot market, freeing up those resources for the use of those that planned adequately.

539. Finally, our proposed enforcement mechanisms are designed to create an incentive to avoid a future penalty or first curtailment. During the public outreach process for developing this proposed rule, some commenters recommended a stronger Independent Transmission Provider role in compliance with a mandatory resource adequacy requirement. One proposal is for the Commission to require the Independent Transmission Provider to procure resources on behalf of load-serving entities that fail to meet fully their requirement and charge them for the cost of the resources.[236] Another is for us to require the Independent Transmission Provider to either (1) calculate an expected capacity deficiency and purchase the call options necessary to meet the adequacy requirement on behalf of the load-serving entities, allocating costs *pro rata*, or (2) require load-serving entities to purchase reserves at the price produced by an Independent Transmission Provider-run auction.[237]

540. These approaches have advantages as well as disadvantages. Among the advantages are that they provide a greater assurance of achieving adequate resources and avoid the possible pitfalls of applying penalty rates or first curtailment. Among the disadvantages are that they take away one demand response option, namely curtailment, from the range of policy choices. Also, the latter approaches appear to require the Independent Transmission Provider to take a position in the capacity market, which places the Independent Transmission Provider in a role that may be incompatible with its independence.[238]

541. What is the effect of these alternate enforcement mechanisms on the incentives and business risks of the

[233] In this section, the term "state regulatory authority" includes the retail rate regulating authority for load-serving entities not regulated by a state utility commission.

[234] Any necessary curtailment action, whether a first curtailment or any subsequent curtailment action may have to satisfy applicable state or local rules for ensuring that essential retail services (such as police, hospitals, fire stations) are maintained.

[235] *See* SMD Tariff, Appendix B, Section I.5.

[236] *See, e.g.*, Electricity Market Design and Structure, Docket No. RM01–12–000, comments of Reliant Resources, Inc., filed May 3, 2002, at pages 11–12, in Docket No. RM01–12–000.

[237] *See, e.g.*, Electricity Market Design and Structure, Docket No. RM01–12–000, comments of Mirant Americas, Inc. and Mirant Americas Energy Marketing, L.P. filed May 2, 2002.

[238] They also raises difficult jurisdictional questions, in that Commission has regulated the seller's side of wholesale transactions and the states have regulated the buyer's side. Under some of these proposals, we would have to distinguish a transmission penalty levied by the Independent Transmission Provider for a load-serving entity's failure to procure the resources needed to maintain transmission security from a Commission-enforced mandatory purchase of reserves by the load-serving entity.

load serving entities in the region? Is there another enforcement mechanism that is both appropriate and effective?

6. Regional Flexibility

542. We propose to apply the requirement set out above to all regions, including regions that already have an ICAP requirement that has been previously approved by the Commission. This requirement would replace the current ICAP program.

543. Some regulators, customers, and market participants have expressed dissatisfaction with the ICAP models presently in place. Some customers view ICAP as an added cost with no tangible benefits; they assert that the commodity being traded has little value because customers are paying for installed capacity but not receiving any greater assurance that generation adequacy is maintained. Some commenters say that, in some ICAP programs, a generator can receive an ICAP payment and later be released from the ICAP obligation for a relatively small penalty to sell its capacity in another market with a high wholesale price.

544. Existing local generators are said to have preferential ability to participate in the ICAP market. The ICAP payment goes to the existing generators and does not necessarily lead others to enter the market to increase capacity. Depending on how the ICAP rules are designed, existing generators may be able to exercise market power, forcing up ICAP prices. In some markets, trading has been so thin at times that there is a question about whether there is a competitive market price.

545. In some such cases, the ISO has intervened to set the price administratively, and market participants are concerned that the price does not reflect the forward value of generating capacity. Some contend that prices in the spot markets and bilateral markets, including long-term forward contract markets, appear to be not well correlated with ICAP market prices.

546. The generators object to ICAP price controls. Some power generators see short-term ICAP payments as providing inadequate assurance of capital cost recovery to motivate new investment. They prefer longer-term contracts to ensure that their investment costs will be recovered.

547. Finally, many parties object that ICAP focuses on power generation, ignoring the potential of demand response.

548. Although we propose that every region must adopt our approach, this approach offers significant regional flexibility. Our approach allows each region to set its own level of resource adequacy, set its own planning horizon, and select from a combination of supply and demand response resources for meeting its needs.

549. Our proposal permits but does not require a region to have its Independent Transmission Provider establish a market for acquiring and trading adequate resources. We believe that the bilateral market and other means can be adequate for acquiring and trading resources. Nevertheless, we ask for comment on whether, under the approach to resource adequacy proposed here, we should require an Independent Transmission Provider to create a market to facilitate load-serving entities meeting their resource adequacy requirement efficiently.

550. Despite the flexibility of our proposed approach, regions with a historical reliance on a tight pool for sharing reserve may argue for a continuation of some form of ICAP program. We ask for comment on how existing Commission-approved ICAP mechanisms can be transitioned and modified so as to be made consistent with our resource adequacy proposal here without disrupting financial commitments made under existing rules. What are the disadvantages of particular elements of the ICAP approach that should be avoided in the approach proposed here? Do any of the enforcement proposals or alternatives discussed above re-introduce any such disadvantageous elements?

K. State Participation in RTO Operations

551. States have an important role in the process of creating and sustaining an efficient competitive wholesale market for electricity. The Commission has already established state-federal RTO panels as a forum for the Commission and state commissioners to discuss issues related to RTO development. However, there currently is not a formal process for state representatives to engage in a similar dialogue with the independent entity that will operate the electric grid under Standard Market Design. Therefore, the Commission is proposing to establish a formal role for state representatives to participate on an ongoing basis in the decision-making process of these organizations.

552. We envision that the Independent Transmission Provider that operates the grid would have a Regional State Advisory Committee. The Regional State Advisory Committee should be formed and should have direct contact with the governing board, in a manner which recognizes its public interest responsibilities, and be designed to provide the board as well as market participants and the Commission with a consensus view from states in the area. The specifics of how this advisory committee would be formed and operate would be decided on a regional basis. This coordinated oversight will ensure fulfillment of federal public interest responsibilities in a manner that includes the views of states throughout the region. In this regard, we also encourage the participation of Canadian provincial authorities in this process.

553. We take note of the recent report by the National Governors' Association entitled ''Interstate Strategies for Transmission Planning,'' which recommends establishing ''Multi-State Entities'' to facilitate state coordination on transmission planning, certification, and siting at a regional level.[239] The report recognizes the critical role states currently play in siting as well as the need to address regional needs. The institution we propose here appears complementary to the National Governors Association's recommendation. In fact, it may be useful to have a single Regional State Advisory Committee rather than separate committees for siting and other issues. We seek comment on whether there should be a single Regional State Advisory Committee, or separate committees for siting and other issues. We also seek comment on how the state representatives should be selected (*e.g.*, whether the governor should select them or some other process should be used).

554. The Regional State Advisory Committee may work with the regional transmission organization to seek regional solutions to issues that may fall under federal, state, or shared jurisdiction, which may include but are not limited to:

a. Resource adequacy standards;
b. Transmission planning, expansion;
c. Rate design and revenue requirements;
d. Market power and market monitoring;
e. Demand response and load management;
f. Distributed generation and interconnection policies;
g. Energy efficiency and environmental issues;
h. RTO management and budget review.

Further duties may evolve with the development and operation of the regional councils.

555. As discussed, the Commission is proposing to require that the independent entity that operates the

[239] *Available in http://www.ng.org/center/divisions/1,1188,C__ISSUE__BRIEF^D__4110,00.html.*

markets under Standard Market Design will have a Market Monitoring Unit (MMU). The MMU will be required to report directly to the Commission and the independent governing board of the Independent Transmission Provider. The MMU should also provide its reports directly to the Regional State Advisory Committee. Finally, because of the regional nature of these organizations, there are many new issues involving rate design and revenue requirements. We believe that the Regional State Advisory Committees 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 intend to work with them to establish protocols for deciding these regional rate issues. Additionally, the Independent Transmission Provider will be required to develop regional plans for transmission planning and expansion. We believe this is also an area where the Regional State Advisory Committee can bring a valuable regional perspective and should be consulted in developing these regional plans.

L. Governance for Independent Transmission Providers

556. The Commission has previously recognized the importance of independent governance of regional organizations in both Order No. 888 and Order No. 2000. In Order No. 888, the Commission required that ISO governance be structured in a fair and non-discriminatory manner and that the ISO be independent of any individual market participant or any one class of participants. The Commission also required that the ISO's rules of governance should prevent control, and appearance of control, of decision-making by any class of participants. Order No. 2000 built upon and extended this independence requirement to RTOs. In Order No. 2000, we reaffirmed our commitment to independence as a bedrock principle for regional organizations, and in this rulemaking we find that our commitment to independence also is critical to the successful implementation of Standard Market Design. Compliance with the independence requirement of Order No. 2000 is based on the independence of the Board of Directors and all employees of the RTO. The governance requirements for the Board of Directors is critical to ensuring that the RTO is independent and that the RTO's interests are aligned with the interests of the market as a whole rather than with particular market participants of classes or market participants. While we did not mandate detailed governance requirements for RTO boards in Order No. 2000, we stated that we would review on a case-by-case basis the RTO governance proposals and judge them against the overarching standard that the RTO's decisionmaking process must be independent of individual market participants and classes of market participants. We also required an audit of the independence of an ISO's governance process two years after its approval as an RTO.[240]

557. The Commission has considered on a case-by-case basis whether individual RTO proposals satisfy the Commission's requirements for independence.[241] We have required changes where they did not.[242] However, we are concerned that the lack of more definitive guidance from the Commission on governance may be hindering the development of larger RTOs. Also, we are concerned that the existing stakeholder process may not provide adequate representation for all market participants and interested parties. The lack of adequate representation may hinder development of alternative energy resources, such as distributed generation, renewable energy, or demand response programs, since these programs may be contrary to the business interests of certain market participants. Therefore, we are proposing to require that all Independent Transmission Providers satisfy specific governance requirements. Specifically, we are proposing to more clearly define the responsibilities of the Board of Directors, more clearly define the role of stakeholders in selection of the board and in the management of the Independent Transmission Provider, and to establish a process that would be used for selecting the Board of Directors by Independent Transmission Providers.

1. Responsibilities of the Board of Directors

558. As we have previously stated in both Order No. 888 and Order No. 2000, it is critical that the board be independent. The board's primary responsibility is to ensure that the markets operated by the Independent Transmission Provider are operated in a fair, efficient and non-discriminatory manner. The board's focus should be on the interests of the wholesale market, not the interests of particular market participants or classes of market participants. The board should not be regarded as a partner or a contractor of the market participants. Further, the board should be composed of members that are not part of the management of the Independent Transmission Provider. This Commission has the overall responsibility for the function of the wholesale electric market, including setting overall policy for the market. Independent Transmission Providers are public utilities subject to the Commission's jurisdiction under the Federal Power Act because they own, control or operate jurisdictional transmission facilities and will administer jurisdictional wholesale energy markets. In order to carry out the functions required by Standard Market Design, the board must be fully independent of any market participants. The board is responsible for overseeing the Independent Transmission Provider's administration of the tariff and market rules that have been approved by the Commission. It also must monitor the operation of the markets within its region to identify problems, *e.g.,* the ability to exercise market power, and to propose solutions. In both of these areas, the board is accountable to the Commission, not the market participants and should ensure the following: system reliability and operating efficiency, efficiently functioning markets, and short- and long-term planning objectives. Indeed, the board should ensure that any instance of perceived or real market power or market dysfunction is reported directly and immediately by the MMU to the Commission.

559. An important implication of these principles is that the board must not be a stakeholder board with industry segments given specific seats on the board. The interest of all board members should be a well-functioning market, not representation of a specific industry segment. Similarly, board members must have no financial interests in market participants so that there is no appearance of bias or benefit.

2. Stakeholder Participation

560. Stakeholders have an important role in advising the boards of Independent Transmission Providers. Most current regional organizations have established stakeholder committees that act either as advisors or in some cases vote on proposals that go

[240] *See* California Operational Audit of the California Independent System Operator issued January 25, 2002 in PA02–1–000 and Order Concerning Governance of the California Independent System Operator 100 FERC ¶61,059 (2002).

[241] *See* Avista Corporation, *et al.*., 95 FERC ¶61,114 (2001).

[242] *See* Carolina Power & Light Company, 94 FERC ¶61,273 (2001).

before the board.[243] We continue to believe that an active stakeholder process is needed and that to fully satisfy the independence principles of Standard Market Design, these stakeholder committees must be used to advise the Board of Directors rather than function as a decision making body.

561. We are concerned that the current composition of these advisory committees may not adequately represent all segments of the industry. The current structure of many ISO stakeholder committees tends to replicate the functions of vertically integrated utilities. For example, PJM currently has five classes, Generation Owners, Transmission Owners, Other Suppliers, Electric Distributors, and End-Use Customers. Four of these classes represent interests that would benefit from higher levels of demand. Only one represents customers or end-users, and none represents demand-side technologies or alternative load control services such as demand resource management. This sector structure could discourage the introduction of changes that implement new demand management technologies and services, one of the biggest potential outgrowths of the move towards a competitive market. Financial entities, which are usually financial trading firms such as banks or other financial institutions that provide the needed capital to the industry, are also poorly represented, if at all. Therefore, we propose to require that an Independent Transmission Provider approved by the Commission must have at a minimum committees that reflect six stakeholder classes: (1) Generators and marketers, (2) transmission owners (this sector would include vertically integrated utilities), (3) transmission-dependent utilities,[244] (4) public interest groups (*e.g.*, consumer advocates, environmental groups, citizen participation), (5) alternative energy providers (*e.g.*, distributed generation, demand response technologies, renewable energy), and (6) end-users and retail energy providers (*i.e.*, load-serving entities that do not own transmission or distribution assets). In addition, we propose to require that there be a separate Regional State Advisory Committee that would advise the board. We believe that six stakeholder classes provides better representation for certain market participants, *e.g.*, transmission-dependent utilities and new technologies that have not been adequately represented in the past. Also, we propose that a company (including all of its affiliates) may have a representative in only one stakeholder sector. For example, a vertically integrated utility that has a marketing affiliate would have to choose whether it would be represented in the transmission owner sector or the generator/marketer sector. This will prevent large corporations from dominating sector representation by placing their affiliates and subsidiaries in several sectors. Initially, the company would be allowed to choose which sector it wished to join. However, requests to change sectors may be subject to limitations to avoid frequent changes that could be used to affect sector voting results for advisory actions recommended to the board. For example, the corporation may be required to decide which sector it will join on an annual basis. This would allow corporations to change sectors to reflect changes in corporate business models, but not allow frequent changes that could be used to change voting results on particular proposals. We also seek comment on whether or under what circumstances, a stakeholder class should be able to take an issue directly to the board outside the stakeholder process.

3. Initial Selection Process for Board of Directors

562. The initial selection process for the Board of directors must be structured to ensure that board members are independent and have expertise in a variety of transmission and electric market areas. We propose that the following process be used.[245]

563. First, the qualifications of the board members should be established. We believe it is important that the qualifications be more widely focused than just experience with electric transmission systems. Experience in additional areas such as risk management, generation planning and operation, or technology and innovation would provide the board with a wider background of knowledge in areas crucial to market development. We propose that board candidates be required to have experience in one or more of these fields: senior corporate leadership of a major publicly traded company; professional disciplines of finance, accounting, or law; electrical engineering; regulation of utilities; transmission system operation or planning; trading or risk management; information technology; and generation planning or operation. The candidate could have experience in the electric industry in either an Investor-Owned Utility or public power entity. The objective is to have a board that collectively possesses experience in many, if not all, of these areas.

564. Board members or their immediate families should not have current or recent ties (within the last two years) as a director, officer or employee of a market participant in the region or its affiliates. Board members or their immediate families should also not have direct business relationships with market participants or their affiliates. Finally, to the extent that the board member owns stocks or bonds of companies that are market participants, these must be divested within six months of being elected to the board. Prior to divestiture, the board member would not be able to participate in any decisions affecting that market participant or its affiliates. These requirements are necessary to ensure that the board member does not have any financial interest in a market participant that could influence the board member's decision. We propose that board members, their immediate families and senior management be required to fill out annual financial disclosure statements to ensure that there is no conflict of interest. The financial disclosure statements would be available for audit by the Commission.

565. Second, a nationally recognized search firm should be retained by the nominating committee to identify candidates that satisfy these criteria. The search firm should supply at least two names for each available board seat. The use of a nationally recognized search firm to develop the list of potential board members helps ensure the integrity of the process since the search firm would not have a financial interest in proposing candidates that represent specific market participants or classes of market participants. The search firm should not have a significant ongoing business relationship with the market participants in the region. The search firm must disclose to the nominating committee any ongoing business relationships it has with market participants in the region.

[243] In Order No. 2000, 23 required that these types of stake holder committees be advisory in RTOs. This meant that the board would have the ability to propose changes to market rules to the commission whether those changes we approved by the stakeholder committees. We propose to continue this policy for Independent Transmission Providers.

[244] These are utilities that must take transmission service from public utilities to provide retail service to their customers.

[245] We are not proposing any specific requirements on the number of board members. We anticipate that the board will have between five and nine members, which is consistent with the current size of the Board of Directors for ISOs and proposed for RTOs.

566. A nominating committee composed of two members from each of the stakeholder classes would be formed to review the list of candidates presented by the search firm. The nominating committee would vote for the individual board candidates as follows. Each nominating committee member would have the right to cast votes equal to the number of open board seats. A member shall not cast more than one vote for any one candidate and is not required to cast all of its votes.

567. Board seats are filled by a simple majority. Candidates with the highest vote totals are elected to open board seats. Ties for the last open board seats will have a runoff subject to the same rules as the initial selection process. The elected board members would vote to designate one of the members as Chairman of the Board. We seek comment on whether the Chief Executive Officer of the Independent Transmission Provider should be a non-voting member of the board.

568. We recognize that allowing a vote on candidates by stakeholders could be perceived as allowing a sector to dominate the board selection process or result in less than a fully independent board. While we recognize the concern, we believe that it is important that stakeholders have a voice in the selection process. We do not believe that it is the Commission's role to be the primary decision-maker in determining the candidates that are selected for the board. We seek comment on what protections should be built into the selection process to ensure that a class of market participants does not dominate the stakeholder voting process. Nevertheless, we solicit comment on whether to require the nominating committee to vote on an entire slate of candidates rather than on individual candidates.

4. Succession of Board Members

569. The governance process also needs to include ongoing procedures for the selection of new board members. We believe that the process should seek to maintain a degree of continuity of board membership to ensure stability and consistency in decisionmaking, while at the same time ensuring that the board does change membership over time to allow the introduction of new viewpoints and encourage innovation.

570. To accomplish these two objectives, we propose that the board members have staggered terms. Approximately half of the first board should have initial terms of four years. The remaining board members should have initial terms of three years. All subsequent board members' terms will be for four years. The staggered terms will provide a degree of continuity to the board in its decision making process. We seek comment on whether the proposed staggered terms would lead to too rapid a turnover in the composition of the board. Board members would be permitted to serve no more than two consecutive terms. This limitation will ensure that there will be a change in board membership over time to allow for the introduction of board members with different experience.

571. The same process that was used to select the initial Board of Directors would be used in the selection process for subsequent board members in the case of resignation, death or removal for cause. Namely a nationally recognized search firm would be retained to identify board candidates. A nominating committee would be formed to review the list of candidates and propose new board members.

572. When the first set of board members terms start expiring a two stage process would be used for electing board members. First, existing board members whose terms are expiring would indicate whether they wished to remain on the board for a second term. The stakeholders would vote on whether these existing board members would remain on the Board of Directors. Second, if there were any remaining vacancies, then a search firm would be retained to provide candidates for the vacant seats on the Board of Directors. The same process that was used for filling the initial Board of Directors would be used for filling these vacancies.

5. Mergers of Independent Transmission Providers

573. We propose the following initial governance structure in the event of a merger of ISOs, RTOs or Independent Transmission Providers. Initially, the board members of the newly formed entity will be comprised of a number of board members from each of the respective organizations in addition to new members. We propose that there should be equal representation from each former organization plus an equal number of new board members.[246] This type of composition will provide the new merged Independent Transmission Provider with the expertise, knowledge and experience during start-up while new board members would bring fresh ideas and perspective. The members from the existing boards will be chosen by their respective boards, after consultation with stakeholders on the expertise and experience needed by the new organization.

574. A nominating committee will nominate all candidates (except the initial members that originate from the original boards of ISOs, RTOs or Independent Transmission Providers) for the initial election of new board members. The initial nominating committee will be composed of two board members from each of the respective merging organizations and the Chairs of two committees representing market operations, reliability and/or management.

M. System Security

575. System security is critical to the reliable operation of the interstate transmission grid. Wholesale electric grid operations are highly interdependent, and a failure of one part of the generation, transmission, or grid management system can compromise the reliable operation of a major portion of the regional grid. The wholesale electric market relies on the continuing reliable operation of not only physical grid resources, but also the operational infrastructure of monitoring, dispatch and market software and systems. Because of this mutual vulnerability and interdependence, it is necessary to safeguard the electric grid and market resources and systems by establishing minimum standards for public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce as well as entities that use these facilities.

576. NERC's Critical Infrastructure Protection Advisory Group has recently developed a set of recommended minimum requirements (standards) for securing information assets that support grid reliability and market operations and the physical environments in which these information assets operate. These standards are designed to ensure that the entity has a basic security program protecting the electric grid and market from the impact of acts, either accidental or malicious, that could cause wide-ranging harmful impacts on grid operations. These standards would be administered through an annual self-certification due January 31, 2004, and every January 31 thereafter. The proposed form for the self-certification is attached as Appendix G.

577. We propose to require that all public utilities that have tariffs on file with the Commission must file the self-certification by January 31, 2004, and every January 31 thereafter. Additionally, on and after February 1, 2004, as a condition of receiving

[246] For example, a nine member board for a merger of two RTOs would reflect 3 members from each of the former RTOs plus three new members.

transmission service provided by a public utility that owns, controls or operates transmission facilities, a customer must demonstrate that it has a basic security program in place. The customer can satisfy this requirement by supplying the public utility with a copy of the executed self-certification form. In the case of entities seeking transmission service that are not public utilities subject to the Commission's regulations, the entity would still be required to demonstrate that it has a basic security program in place to receive transmission services. This could be done by supplying the transmission provider with an executed self-certification using the Commission's form. Alternatively, the transmission provider and the customer could develop an alternative arrangement for ensuring that the customer has a basic security program in place.

578. Finally, when the SMD Tariff is implemented, we propose to extend the requirement to cover the additional services being provided by the Independent Transmission Provider. At that time, any customer seeking to buy or sell through the markets operated by the Independent Transmission Provider or take transmission service under the Network Access Service would be required to demonstrate that it has a basic security program in place.

579. We expect that these standards will be revised and refined over time in light of changes in technology and operational experience with the standards. Therefore, the regulations will also identify the specific version number of the system security standards. When NERC revises the standards, the revisions will be filed with the Commission. The Commission will issue a Notice that it is considering revising the updated system security standards, and we will seek comments on the proposed changes. These security standards for electric market participants can be found in Appendix G, along with the proposed self-certification form, discussed above.

V. Implementation

580. The Commission proposes to find in the Final Rule that rates, terms and conditions of transmission service and wholesale electric sales that do not comport with the regulations adopted by the Final Rule are unjust, unreasonable or unduly discriminatory. Many of the elements included in Standard Market Design will require computer software development and changes that public utilities may not be able to fully implement for a couple of years. The Commission's objective is to have Standard Market Design implemented on all jurisdictional transmission systems no later than September 30, 2004, or such time as the Commission may establish. The Commission does not believe it is in the public interest to delay implementation of the remedial action to cure undue discrimination or to develop necessary infrastructure until the time when all of the software changes necessary for standard market design are completed. Consequently, the Commission proposes a multi-step process that will be used to bring these rates, terms and conditions of service into conformity with the regulations.

30 Days After Effective Date of Final Rule

581. The Commission will require all public utilities that own, control or operate interstate transmission facilities to begin discussions with stakeholders and state representatives within 30 days after the effective date of the Final Rule about how they will implement the transition process and comply with the requirements of the Final Rule. These discussions should address selection of an Independent Transmission Provider that will manage the transmission facilities, establishment of a regional state advisory committee, development of a regional transmission planning and expansion program, development of a long-term resource adequacy requirement and identification of areas such as load pockets where mitigation or appropriate infrastructure will be necessary.

July 31, 2003

582. The Commission recognizes that it has accepted many changes to the *pro forma* tariffs of individual transmission providers that deviate from the *pro forma* tariff contained in Order No. 888. To the extent these changes involve bundled retail load or give preference to either native load customers or the transmission provider's use of its system, we propose to direct the transmission provider to eliminate them. We have revised the Order No. 888 *pro forma* tariff to place bundled retail load under the open access transmission tariff, and to eliminate undue preferences for native load customers and the transmission owner's use of its own system.[247] The revised Order No. 888 *pro forma* tariff, which is referred to as the Interim Tariff in this proposed rule, is attached as Appendix A. Pursuant to section 206 of the FPA, we propose to require all public utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce to file the Interim Tariff, no later than July 31, 2003. The Interim Tariff will become effective on September 30, 2003, after the peak summer season.

583. Although a transmission tariff rate is already in effect for all public utilities that own, operate or control facilities used for the transmission of electric energy in interstate commerce, we acknowledge that changes to individual utility rates may be necessary as a result of the changes to non-rate terms and conditions that the Interim Tariff requires. Should a public utility determine that such rate changes are warranted by the new non-rate terms and conditions, it may file a new rate proposal pursuant to FPA section 205, no later than July 31, 2003. We will impose a blanket suspension on any such filings that we receive and make them effective, subject to refund, 61 days after they are filed.

584. We also propose a new tariff (SMD Tariff), attached as Appendix B, to supersede the Interim Tariff and implement Standard Market Design. The new SMD Tariff includes many areas in which the Independent Transmission Provider would propose provisions consistent with the policy framework set forth in the Final Rule, but designed to meet the specific circumstances of the region. We propose to give regions discretion in developing a transition program for existing contracts that is consistent with the guidelines set forth in the Final Rule.

585. The Commission recognizes that public utilities will need time to ensure that transmission facilities are operated by an Independent Transmission Provider, implement Network Access Service, establish day-ahead and real-time markets, adopt LMP for congestion management, incorporate market power mitigation measures customized for the region, develop a market monitoring program and develop a resource adequacy requirement for the region. Thus, for these requirements the Commission proposes a process for implementation that provides an opportunity for active participation by state representatives and market participants and that gives the Commission opportunities to review progress and require changes if sufficient progress is not being made.

586. To implement the requirements of Standard Market Design, we propose to require every public utility that owns, controls or operates facilities used for the transmission of electric energy in

[247] The public utility would make the revisions to its currently effective Open Access Transmission Tariff. The changes to the Order No. 888 tariff are intended to identify the changes that must be made.

interstate commerce to select an Independent Transmission Provider to operate its transmission facilities. A public utility may meet this requirement by: (1) Itself satisfying the definition of Independent Transmission Provider; (2) turning over its transmission facilities to a Commission-approved RTO that meets the definition of Independent Transmission Provider; or (3) contracting with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities.

587. The Commission will require all public utilities that own, operate or control interstate transmission facilities to file an Implementation Plan for compliance with the regulations no later than July 31, 2003. In the Implementation Plan, the public utility must identify the independent entity that will serve as the Independent Transmission Provider for the transmission facilities that the public utility owns, controls or operates. (A public utility that is already a member of an entity that satisfies the definition of Independent Transmission Provider may request a waiver from this requirement in its Implementation Plan filing.) Additionally, the Implementation Plan must include time lines and a proposal for compliance with the long-term resource adequacy requirements of the Final Rule. Further, the Implementation Plan must identify the software vendor(s) that the public utility will use for implementation of Standard Market Design and a time line that identifies implementation milestones and indicates the projected timing of their completion. The Commission wants to ensure that the cost of implementation of Standard Market Design is reasonable, and intends to closely monitor the expenditures incurred to implement the Final Rule. Therefore, we propose to require that all public utilities include in their Implementation Plan a detailed estimate of their projected cost of implementing the Final Rule. The estimate should include projected software costs as well as other costs that the public utility may incur. The public utility will also be required to file status reports on the Implementation Plan on a quarterly basis. The Commission will review the Implementation Plans and quarterly reports to ensure compliance with the regulations. Also, the Commission will establish appropriate procedures, if needed, for resolving concerns of state representatives and market participants.

588. The Commission recognizes that some public utilities will be able to implement Standard Market Design more quickly than others. The dates proposed in the Implementation Plan should reflect the level of changes that are required. The Commission intends to be flexible in setting compliance dates for Standard Market Design. The Commission expects that those public utilities that do not require significant changes could implement Standard Market Design much sooner than others. While the Commission's objective is to have Standard Market Design in place everywhere by September 30, 2004, it will consider requests to extend this date if the public utility can document that additional time is necessary.

589. Finally, the public utility must cooperate with others in its region to have a Regional State Advisory Committee in place by July 31, 2003.

Six Months After Effective Date of Final Rule

590. The Commission proposes to require all public utilities that own, control or operate facilities used for the transmission of electric energy in interstate commerce to begin a regional transmission planning process within six months and produce a plan within one year of the effective date of the Final Rule. This will be an intermediate step in the process of satisfying the planning and expansion requirements contained in section 35.34(k)(7) of the Commission's regulations.[248] The Independent Transmission Provider will take over this process when it becomes operational.

December 1, 2003 and September 30, 2004

591. Pursuant to section 206 of the FPA, by December 1, 2003 all Independent Transmission Providers will be required to file the SMD Tariff, including language that explains the Independent Transmission Provider's proposals for market monitoring, market power mitigation, long-term resource adequacy, transmission planning and expansion, transmission pricing and any changes to the SMD Tariff necessary to accommodate regional needs. The filing must also indicate the date, which must be no later than September 30, 2004, or such date as the Commission may establish, when the Independent Transmission Provider will be able to fully implement Standard Market Design. The Commission must approve the tariff filing before the Independent Transmission Provider will be able to implement Standard Market Design. We anticipate acting on these filings on a timely basis so that the Independent Transmission Providers will know several months before the planned implementation date any changes that are required in these filings.

592. As a result of the changes required by the Final Rule, the Independent Transmission Provider or transmission owners may believe that other changes are needed in their transmission rates for jurisdictional service. Transmission owners and Independent Transmission Providers should file these types of changes under section 205 of the FPA at least 60 days prior to the date on which they propose to implement Standard Market Design. The Commission intends the implementation process to be a collaborative one. The Commission directs public utilities to meet with stakeholders and state commissions on a regular basis to discuss the changes that are necessary to comply with the Final Rule. Based on the filings that are received, the Commission may also establish technical conferences, mediation efforts or other procedures as necessary to ensure that all public utilities that own, control or operate interstate transmission facilities will be operating under Standard Market Design no later than September 30, 2004, or such time as the Commission may establish.

593. Further, the Commission intends this phased compliance process to encourage joint compliance filings. Public utilities may submit a single, joint application to meet the requirements of Standard Market Design, and Independent Transmission Providers may make necessary filings on behalf of their public utility members. Such joint filings may streamline the compliance process and reduce its costs.

January 31, 2004

594. The Commission proposes to require all public utilities to provide assurances to the Independent Transmission Provider with which they are affiliated that the public utilities comply with minimum security standards. We propose to require public utilities that have transmission tariffs on file with the Commission to file the self-certification of compliance with security standards that is attached as Appendix G. The self-certification must be submitted by January 31, 2004, and every January 31 thereafter. On and after February 1, 2004, any transmission customer (including a non-jurisdictional entity) that seeks to receive transmission service from a public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must provide assurances to the transmission provider that it has a basic security system in

[248] 18 CFR 35.34(k)(7) (2002).

place. This may be done by providing the transmission provider with a copy of the executed self-certification form, or the transmission provider and customer may make alternate arrangements. Following the implementation of Standard Market Design, we propose to extend this self-certification requirement to apply to any customer seeking to buy or sell through the Independent Transmission Provider's markets or take Network Access Service.

VI. Public Comment Procedures

595. The Commission invites interested persons to submit comments, data, views and other information concerning matters set out in this proposed rule. To facilitate the Commission's review of the comments, the Commission requests commenters to provide an executive summary (not to exceed ten pages) of their positions. To the greatest degree possible, commenters should use the topic headings that the proposed rule uses and arrange their comments in the order of topics presented in this proposed rule, and cite the specific referenced paragraph numbers. Commenters should identify separately any additional issues that they may wish to address. Commenters should double-space their comments. Comments must refer to Docket No. RM01–12–000, and may be filed on paper or electronically via the Internet. The Commission must receive all comments no later than October 15, 2002. Comments should include an executive summary that should not exceed ten pages. Those filing electronically do not need to make a paper filing. Reply comments will not be entertained.

596. Those making paper filings should submit the original and 14 copies of their comments to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426.

597. The Commission strongly encourages electronic filings. Commenters filing their comments via the Internet must prepare their comments in WordPerfect, MS Word, Portable Document Format, or ASCII format (*see http://www.ferc.gov/documents/electronicfilinginitiative/efi/efi.htm,* in particular ''User Guide''). To file the document, access the Commission's Web site at *www.ferc.gov* and click on ''e-Filing'' and then follow the instructions for each screen. First time users will have to establish a user name and password. The Commission will send an automatic acknowledgment to the sender's e-mail address upon receipt of comments. User assistance for electronic filing is available at 202–208–0258 or by e-mail to *efiling@ferc.gov.* Do not submit comments to the e-mail address.

598. The Commission will place all comments in the Commission's public files and they will be available for inspection in the Commission's Public Reference Room at 888 First Street, NE., Washington, DC 20426, during regular business hours. Additionally, all comments may be viewed, printed, or downloaded remotely via the Internet through FERC's home page using the FERRIS link.

VII. Regulatory Flexibility Act

599. The Regulatory Flexibility Act [249] requires rulemakings to contain either a description and analysis of the effect that the proposed rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities.

600. This rule applies to public utilities that own, control or operate interstate transmission facilities, not to electric utilities per se. The total number of public utilities that, absent waiver, would have to modify their current open access transmission tariffs by filing the Interim Tariff is 176.[250] Of these only 6 public utilities, or less than two percent, dispose of 4 million MWh or less per year.[251] We do not consider this a substantial number, and in any event, these small entities may seek waiver of the Standard Market Design Final Rule requirements.[252]

601. With respect to the Interim Tariff, the Commission will specify precisely the terms and conditions that public utilities will have to incorporate into their existing tariffs, and this will considerably reduce the burden of modifying transmission tariffs. In order to implement the SMD Tariff, every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must (a) meet the definition of Independent Transmission Provider, (b) turn over the operation of its transmission facilities to a regional transmission organization that meets the definition of Independent Transmission Provider, or (c) contract with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities. We do not expect that any entity that must file an SMD Tariff would be a small entity as defined by the Regulatory Flexibility Act.

602. We do not, therefore, believe that the requirement of filing the Interim Tariff and SMD Tariff will impose a significant economic impact on small entities. Consequently, the Commission certifies that this proposed rule will not have a significant economic impact upon a substantial number of small entities.

VIII. Environmental Statement

603. In furtherance of the National Environmental Policy Act of 1969, the Commission will prepare an environmental assessment (EA) that will consider the environmental impacts of the proposed rule. A notice of intent to prepare the EA, including a request for comments on the scope of the EA and notice of a public scoping meeting was issued on July 26, 2002.[253]

IX. Public Reporting Burden and Information Collection Statement

604. The Commission is submitting the following collections of information contained in this proposed rule to the Office of Management and Budget (OMB) for review under section 3507(d) of the Paperwork Reduction Act of 1995. The Commission identifies the information provided under Part 35 as FERC–516.

605. The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimates, ways to enhance the quality, utility and clarity of the information that the Commission will collect, and any suggested methods for minimizing respondent's burden, including the use of automated information techniques.

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[249] 5 U.S.C. 601–612 (1994).

[250] The sources for this figure are FERC Form No. 1 and FERC Form No. 1–F data.

[251] *Id.*

[252] The Regulatory Flexibility Act defines a ''small entity'' as ''one which is independently owned and operated and which is not dominant in its field of operation.'' *See* 5 U.S.C. 601(3) and 601(6) (1994); 15 U.S.C. 632(a)(1) (1994). In *Mid-Tex Elec. Coop.* v. *FERC,* 773 F.2d 327, 340–343 (D.C. Cir. 1985), the court accepted the Commission's conclusion that, since virtually all of the public utilities that it regulates do not fall within the meaning of the term ''small entities'' as defined in the Regulatory Flexibility Act, the Commission did not need to prepare a regulatory flexibility analysis in connection with its proposed rule governing the allocation of costs for construction work in progress (CWIP). The CWIP rules applied to all public utilities. The Standard Market Design rules will apply only to those public utilities that own, control or operate interstate transmission facilities. These entities are a subset of the group of public utilities found not to require preparation of a regulatory flexibility analysis for the CWIP rule.

[253] Notice of Intent to Prepare an Environmental Assessment and Request for Comments on the Scope of Issues to be Addressed for the Proposed Rulemaking on Electricity Market Design and Structure, Docket No. RM01–12–000 (July 26, 2002).

The burden estimates for complying with this proposed rule are as follows:

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
FERC–516	176 176 12	1 4 1	*1,199 3 164	211,024 2,112 1,968
Totals			1,366	215,104

*Rounded off.

Respondent	Document	Recipient	Required content	Hours per response
All public utilities that own, operate or control transmission facilities.	(no document required).	Stakeholders and state representatives.	Public utilities must discuss with stakeholders and state representatives how they will implement the transition process and comply with the Final Rule: 1. Selection of Independent Transmission Provider. 2. Establishment regional state advisory committee. 3. Development of regional transmission planning /expansion program. 4. Development of a long-term resource adequacy requirement. 5. Identification of areas where mitigation or appropriate infrastructure will be needed.	430 hours
All public utilities that own, operate or control transmission facilities.	Revisions to Order No. 888 tariff (Interim Tariff) or request for waiver of this requirement.	FERC	Tariff language to place service to bundled retail customers under OATT, eliminate preferences for native load and for a transmission provider's own use of its system.	182 hours
All public utilities that own, operate or control transmission facilities.	Implementation plan for compliance with proposed regulations.	FERC	1. Identify Independent Transmission Provider (or request waiver of this requirement). 2. Time lines and proposed procedures for regional transmission planning process. 3. Time line and proposal for compliance with long-term resource adequacy requirements. 4. Identify software vendor(s) to be used for implementation of SMD. 5. Implementation time line showing projected timing and completion of milestones for software development. 6. Detailed estimate of costs of implementing SMD.	193 hours
Public utilities	Quarterly Reports	FERC	Implementation Plan Status	3 hours
Transmission Provider	Proposed tariff language.	FERC	1. SMD Tariff, including proposed language for market monitoring and market power mitigation; long-term resource adequacy; transmission planning and expansion; changes to SMD Tariff needed to accommodate regional needs. 2. Date by which transmission provider will fully implement SMD.	124 hours
Transmission Provider	Section 205 filing requesting approval of adjustment of revenue requirement (optional).	FERC	Section 205 filing demonstrating that transmission provider's revenue requirement should be adjusted to recover additional costs associated with conversion pre-Order No. 888 contracts to service under new tariff and allocation of congestion revenue rights directly to customers.	*If respondent decides to submit a § 205 filing, the burden is already covered under existing requirements

Respondent	Document	Recipient	Required content	Hours per response
Transmission Provider/participating generators.	Participator Generator agreements.	FERC	1. Identify noncompetitive conditions in which generator would have to selfschedule or supply all capacity to spot markets. 2. Specify bid caps that would apply to generator's day-ahead and real-time bids.	34 hours
Transmission Provider	Reliability proposals ...	FERC	Proposal regarding implications of each reliability procedure (e.g. curtailment) for market prices in energy and ancillary services markets.	63 hours
Transmission Provider	Transmission Expansion Plan.	FERC	Have in place a regional transmission planning process and complete first transmission expansion plan pursuant to 18 CFR 35.34(k)(7).	120 hours
Market Monitoring Unit	Initial competitive market analysis.	FERC	1. Identify load pockets that require different bid mitigation triggers. 2. Identify generators that may be required for reliability.	78 hours
Market Monitoring Unit	Annual report on market operations.	FERC & Independent Transmission Provider's Governing Board.	1. General description—market operations, supply and demand, market prices. 2. Analysis of market structure and participant behavior. 3. Evaluation of effectiveness of mitigation measures taken. 4. Overall assessment of market efficiency. 5. Evaluation of barriers to entry for generating, demand-side, and transmission resources. 6. Recommended changes to market design or market power mitigation measures to improve market performance.	86 hours
Load serving entities ..	Resource adequacy report.	RTO	Report and document plan to meet share of regional adequacy requirement.	38 hours
RTOs	Regional Demand Forecast.	RTO	Regional demand forecast for its region for the planning horizon.	To be determined
All public utilities with a transmission tariff on file with the Commission.	Self-certification of compliance with system security standards.	FERC	Completed and executed form contained in Appendix G to Notice of Proposed Rulemaking.	2 hours
All public utilities with a transmission tariff on file with the Commission.	Annual recertification of compliance with system security standards.	FERC	Completed and executed form contained in Appendix G to Notice of Proposed Rulemaking.	.5 hours

Total Annual Hours for Collection (reporting + record keeping (if appropriate) = 215,104 hours.

Information Collection Costs

606. Because of the regional differences and the various staffing levels that will be involved in preparing the documentation (legal, technical and support) the Commission is using an hourly rate of $50 to estimate the costs for filing and other administrative processes (reviewing instructions, adjusting existing ways to comply with previously applicable instructions or requirements, training personnel to be able to respond to the information collection, searching data sources, completing and transmitting the collection of information and conducting outreach sessions with all affected entities) associated with this proposed rule. The estimated cost is anticipated to be $10,755,200 (215,104 hours × $50) for this portion of the rule.

607. In addition, there is a separate component that must also be considered when implementing the requirements of this proposed rule, the costs for information technology (IT) needed to implement the SMD Tariff. The number of entities to be impacted at this phase of the rule's implementation will be fewer than at the Interim Tariff stage, but is still unknown at this time. Further, several entities are already developing or employing software that may be sufficient to implement the SMD Tariff, and the entities' software packages are at different stages of development. There are also regional differences to consider (as noted above) with respect to labor compensation. For these reasons, the Commission seeks comments on the anticipated costs for IT development associated with this proposed rule. When preparing their estimates, commenters should take into consideration design, procurement and operation costs for the following: (1) Data collection systems (including monitors, detection systems, control

systems and other equipment necessary to obtain information or data of interest, as well the facilities and equipment necessary to house and operate such systems); (2) data management systems necessitated by the data collection(s) (including computers and other hardware, programs and other software, storage media and facilities); and (3) data reporting systems necessitated by the information collection (including electronic links, installing and operating the reporting components of an information management system and the burden of maximizing public accessibility). These investments in information technology are for systems whose useful lifetime exceeds the expiration of the data collection (which must be reviewed and approved by OMB after three years), so the costs for this reporting burden needs to be estimated based on the costs of a longer lived investment. OMB regulations require OMB to approve certain information collection requirements imposed by agency rule.[254] Accordingly, pursuant to OMB regulations, the Commission is providing notice of its proposed information collections to OMB.

Title: FERC–516, Electric Rate Schedule Filings.

Action: Proposed Data Collections.

OMB Control No.: 1902–0096.

The applicant shall not be penalized for failure to respond to this collection of information unless the collection of information displays a valid OMB control number.

Respondents: Business or other for profit.

Frequency of Responses: One time.

Necessity of Information: The proposed rule would revise the requirements contained in 18 CFR part 35. The Commission is seeking to standardize wholesale electric market design and transmission service. The Commission proposes to develop a standardized set of electricity market rules that reflects many of the recommendations and suggestions elicited from all market participants.

608. The proposed SMD rules are intended to have a generally positive impact on these market participants. For example, the proposed SMD rules will facilitate direct dealings between market participants who want to secure long-term bilateral power supply arrangements. The proposed SMD rules will also facilitate short-term transactions that are made in the spot market to make up for imbalances (differences) between scheduled electricity supplies that were matched to projected load levels, and the load levels that actually develop. Through these proposed SMD rules, sellers will be able to more effectively sell into the market and buyers will be able to more efficiently buy from the market because they will not need to be directly matched up at the last minute on a real-time hourly and day-ahead basis. In addition, the proposed SMD rules will bolster the ability of many smaller customers, as well as larger customers, to profitably participate in programs designed to encourage reductions in loads to offset electricity supply shortages. Finally, the proposed SMD rules will foster the trading of transmission rights among transmission customers that will allow them to hedge against transmission congestion surcharges.

609. Up to 176 public utilities that own, operate or control transmission would be required to implement the Commission's SMD Rule. The revised open access transmission component of the SMD Rule would be incorporated as an interim amendment to the existing transmission tariffs of all jurisdictional transmission providers operating in interstate commerce. Independent Transmission Providers would also be required to file SMD Tariffs contained in the Final Rule to implement Network Access Service and Standard Market Design. To the extent an affected public utility participates in an RTO, or contracts with an Independent Transmission Provider, the RTO or Independent Transmission Provider would make the required filing on behalf of the affected public utility. Public utilities also will be permitted to file Implementation Plans jointly with other utilities. Further, the Commission proposes to entertain requests for waivers of the requirement to make compliance filings. These features of the proposed rule would lessen the incidence of SMD compliance filings. We have estimated for purposes of this analysis that RTOs and ITPs may number from 5 to 12 entities in the lower 48 states.

Internal Review: The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements. The Commission's Office of Markets, Tariffs and Rates will use the data included in filings under Sections 203 and 205 of the Federal Power Act to evaluate efforts for the interconnection and coordination of the United States electric transmission system and to ensure the orderly formation and operation of a standard design in wholesale electric transmission markets, as well as for general industry oversight. These information requirements conform to the Commission's plan for efficient information collection, communication, and management within the electric power industry.

610. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington DC 20426 [Attention Michael Miller, Capital Planning and Policy Group, Phone: (202) 502–8415, fax: (202) 208–2425, e-mail: *michael.miller@ferc.gov.*]

611. Please send your comments concerning the collection of information(s) and the associated burden estimates to the contact listed above and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–7856, fax: (202) 395–7285].

X. Document Availability

612. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's home page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m., to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

613. From FERC's home page on the Internet, this information is available in the Federal Energy Regulatory Records Information System (FERRIS). The full text of this document is available on FERRIS in PDF and WordPerfect format for viewing, printing, and/or downloading. To access this document in FERRIS, type the docket number of this document, excluding the last three digits in the docket number field.User assistance is available for FERRIS and the FERC's Web site during normal business hours from our Help Line at (202) 208–2222 (e-mail to *WebMaster@ferc.gov*) or the Public Reference at (202) 208–1371 Press 0, TTY (2020) 208–1659 (e-mail to *public.reference.room@ferc.gov*).

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Electricity, Reporting and recordkeeping requirements.

[254] *See* 5 CFR 1320.11 (2002).

By direction of the Commission. Commissioner Breathitt concurred with a separate statement attached.

Magalie R. Salas,

Secretary.

In consideration of the foregoing, the Commission proposes to amend Part 35, Chapter I, Title 18, *Code of Federal Regulations*, as follows.

Regulatory Text

PART 35—FILING OF RATE SCHEDULES

1. The authority citation for Part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

2. Part 35 is amended by adding a new Subpart G, Procedures and Requirements Regarding Non-Discriminatory Open Access Transmission Services and Standard Market Design, including new §§ 35.35, 35.36, 35.37 and 35.38 to read as follows:

Subpart G—Procedures and Requirements Regarding Non-Discriminatory Open Access Transmission Services and Standard Market Design

Subpart G—Procedures and Requirements Regarding Non-Discriminatory Open Access Transmission Services and Standard Market Design

§ 35.35 Standard Market Design Tariff.

(a) Applicability. This section applies to any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce and to any Independent Transmission Provider.

(b) Definitions—

(1) *Independent Transmission Provider.* As used herein the term *Independent Transmission Provider* shall mean any public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, that administers the day-ahead and real-time energy and ancillary services markets in connection with its provision of transmission services pursuant to the pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____ (Final Rule on Electricity Market Design and Structure), and that is independent (*i.e.*, has no financial interest, either directly or through an affiliate, as defined in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. 79b(a)(11)), in any market participant in the region in which it provides transmission services or in neighboring regions).

(2) *Market Participant.* As used herein the term *Market Participant* shall mean:

(i) Any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides ancillary services to the Independent Transmission Provider, unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the Independent Transmission Provider's actions or decisions; and

(ii) Any other entity that the Commission finds has economic or commercial interests that would be significantly affected by the Independent Transmission Provider's actions or decisions.

(c) Non-discriminatory open access transmission services and standard market design.

(1) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce, shall provide non-discriminatory open access services through the interim tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____(Final Rule on Electricity Market Design and Structure) no later than September 30, 2003. Such tariff shall remain on file with the Commission until it is superseded by the pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶ ____ (Final Rule on Electricity Market Design and Structure).

(2) To implement the requirements of Non-Discriminatory Open Access Transmission Services and Standard Market Design, every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must meet the definition of Independent Transmission Provider, turn over the operation of its transmission facilities to a regional transmission organization, as defined in § 35.34(b)(1) of this title, that meets the definition of Independent Transmission Provider, or contract with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities.

(i) Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce as of [effective date of Standard Market Design Rule] must comply with this requirement by September 30, 2004, or such other date as determined by the Commission. Such public utility must inform the Commission which Independent Transmission Provider will operate the public utility's transmission facilities, and provide further information about its plans to implement Standard Market Design as specified in Order No. ____, FERC Stats. & Regs. ¶ ____, no later than July 31, 2003. Every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce after the effective date of this rule must comply no later than 60 days prior to the time its facilities are used for transmission in interstate commerce.

(ii) A public utility that is a member of an approved regional transmission organization or an independent system operator or other entity that meets the definition of Independent Transmission Provider may file a request for a waiver of the filing requirements of this paragraph on the ground that it has already complied with the requirement. An application for a waiver must be filed no later than July 31, 2003, or no later than 60 days prior to the time the public utility's transmission facilities are used for transmission in interstate commerce.

(3) Pursuant to section 206 of the Federal Power Act, any entity that meets the definition of Independent Transmission Provider must file with the Commission a tariff of general applicability for the provision of transmission services, including ancillary services and the administration of the day-ahead and real-time energy and ancillary services markets. Such tariff must be the pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶____ (Final Rule on Electricity Market Design and Structure) or such other open access tariff as may be approved by the Commission consistent with Order No. ____, FERC Stats. & Regs. ¶____ (Final Rule on Electricity Market Design and Structure). Such tariff must include proposed language that explains the Independent Transmission Provider's proposals for market monitoring, market power mitigation, long-term resource adequacy, transmission planning and expansion, transmission pricing, changes to the pro forma tariff necessary to accommodate regional needs, and further information as specified in the pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶____ (Final Rule on Electricity Market Design and Structure). The filing also shall specify the date on which the Independent Transmission Provider proposes to implement Standard Market Design.

(4) The Independent Transmission Provider shall file, pursuant to section

205 of the Federal Power Act, any changes to its transmission rates necessary to implement Standard Market Design, no later than 60 days prior to the date on which it proposes to implement Standard Market Design, or 60 days prior to the time its facilities are used for transmission in interstate commerce.

(5) One or more public utilities may jointly file an application to meet the requirements of this paragraph.

(6) An Independent Transmission Provider may make necessary filings on behalf of public utilities required to meet the requirements of this paragraph.

(7) The interim tariff and pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶____ (Final Rule on Electricity Market Design and Structure) will not apply to transmission of electric energy pursuant to contracts that were executed on or before July 9, 1996 and remain in effect as of [effective date of Standard Market Design Rule]. Customers under such contracts may elect to convert their contracts, consistent with their contract terms, to service under the pro forma tariff contained in Order No. ____, FERC Stats. & Regs. ¶____ (Final Rule on Electricity Market Design and Structure) at any time after [effective date of Standard Market Design Rule].

(8) Waivers. A public utility subject to the requirements of this section may file a request for waiver of all or part of the requirements of this section, for good cause shown. An application for waiver must be filed no later than [effective date of Standard Market Design Rule], or no later than 60 days prior to the time the Independent Transmission Provider would otherwise have to comply with the requirement.

(d) Non-public utility procedures for tariff reciprocity compliance.

(1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff provides transmission service that is comparable to the service that the non-public utility provides itself.

(i) Any submittal and request for declaratory order submitted by a non-public utility will be provided an NJ (non-jurisdictional) docket designation.

(ii) If the submittal is found to be an acceptable transmission tariff, an applicant in a Federal Power Act (FPA) section 211 case against the non-public utility shall have the burden of proof to show why service under the open access tariff is not sufficient and why a section 211 order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access tariff, for good cause shown. An application for waiver may be filed at any time.

(3) If a non-public utility has on file with the Commission, as of [effective date of Standard Market Design Rule], a reciprocity tariff accepted by the Commission, the non-public utility is not required to make a filing under paragraph (d) of this section.

§ 35.36 Market monitoring and market power mitigation.

(a) The Independent Transmission Provider must have a market monitoring unit that is independent of the Independent Transmission Provider's management and that is accountable to the Commission. The market monitoring unit will provide information and recommendations to the Commission and the governing board of the Independent Transmission Provider.

(b) The market monitoring unit will monitor all markets run by the Independent Transmission Provider and the operation of the transmission grid for exercises of market power, flaws in the Independent Transmission Provider's tariff rules or operations that contribute to economic inefficiency, and market participants' compliance with the Independent Transmission Provider's tariff. The market monitoring unit also shall perform further duties as instructed by the Commission.

(c) The market monitoring unit will report at least annually on the structure and performance of the markets in the Independent Transmission Provider's region. The report must include, at a minimum: a description of market operations, supply and demand, and market prices; an structural analysis of the market, including an evaluation of barriers to entry; an assessment of market performance, including an assessment of market participant behavior; an evaluation of the effectiveness of the existing market power mitigation; and recommendations for improving the market design or market power mitigation measures to improve the efficiency of the market. The market monitoring unit also shall provide further reports as directed by the Commission.

(d) The Independent Transmission Provider must include in its tariff provisions requiring market participants, as a condition of participating in the markets operated by the Independent Transmission Provider and using the interstate transmission facilities operated by the Independent Transmission Provider.

(1) To agree to provide to the market monitoring unit all information and data requested by the market monitoring unit to perform its functions under these rules and the Independent Transmission Provider's tariff, and

(2) To agree to penalties specified in the Independent Transmission Provider's tariff for the violation of any tariff provisions.

(e) The market monitoring unit is responsible for administering the market power mitigation provisions of the Independent Transmission Provider's tariff.

§ 35.37 Long-term electric energy resource adequacy.

(a) Each Independent Transmission Provider must ensure that the level of planned regional resources for a future year (the last year of the planning horizon) is adequate. Annually, each Independent Transmission Provider must:

(1) Perform an electric energy demand forecast for the last year of the planning horizon;

(2) Apportion the regional resource adequacy requirement for the last year of the planning horizon among the load serving entities in its area on the basis of the ratio of their loads;

(3) Require each load-serving entity in its area to submit to the Independent Transmission Provider a plan (including generation, transmission and demand-side options) to meet the load-serving entity's share of the regional resource adequacy requirement for the last year of the planning horizon; and

(4) Ensure that each load-serving entity's electric energy resource plan meets standards approved by the Commission and is feasible, including ensuring that resources are not double counted by different load serving entities.

(b) This requirement shall replace installed capacity requirements approved by the Commission prior to [effective date of Standard Market Design Rule].

§ 35.38 Long-term transmission planning and expansion.

(a) Each Independent Transmission Provider shall keep on file with the Commission a regional transmission expansion plan.

(b) Each Independent Transmission Provider's regional transmission expansion plan shall, at a minimum:

(1) permit all market participants to participate equally in a facilitated process to identify transmission projects that would best serve the needs of the region; and

(2) require the Independent Transmission Provider to issue requests for proposals to address transmission planning needs identified through such a process.

(c) Independent Transmission Providers shall satisfy the provisions of § 35.34(k)(7) of this title no later than the date on which service commences under Standard Market Design.

Note: The following Appendices will not be published in the Code of Federal Regulations.

APPENDICES

A. INTERIM *PRO FORMA* TARIFF REVISIONS
B. STANDARD MARKET DESIGN TARIFF (SMD TARIFF)
C. EXAMPLES OF FLAWS IN THE CURRENT REGULATORY ENVIRONMENT
D. CONVERSION OF THE ORDER NO. 888 *PRO FORMA* TARIFF TO THE REVISED STANDARD MARKET DESIGN *PRO FORMA* TARIFF
E. STANDARD MARKET DESIGN AND TRADING STRATEGIES ENCOUNTERED IN INDEPENDENT SYSTEM OPERATORS
F. ACCESS CHARGES AND CONGESTION REVENUE RIGHTS
G. FORM FOR ANNUAL SELF-CERTIFICATION OF COMPLIANCE WITH FERC SECURITY STANDARDS

Appendix A—Proposed Revisions to Order No. 888—A Pro Forma Open Access Transmission Tariff

Among the revisions that the Commission proposes to require the Transmission Provider to file are revisions to Sections 1.19, 13.5, 13.6, 14.2, 22.1(a), 28.2, 28.3, 33.2, 33.3, 33.5, and 33.7 to recognize that the preferences contained in the tariff for native load customers and for the Transmission Provider's use of its system have been eliminated. The changes are set forth below:

1.19 Native Load Customers: The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers. The Transmission Provider will take Network Integration Transmission Service under Part III of the Tariff on their behalf.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to all customers taking firm service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers, including transmission service taken by the Transmission Provider for native load, and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

14.2 Reservation Priority: Non-Firm Point-To-Point Transmission Service shall be available from transmission capability in excess of that needed for reliable service to Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) Immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

22.1 Modifications On a Non-Firm Basis: The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement (''Secondary Receipt and Delivery Points''), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff.

28.2 Transmission Provider Responsibilities: The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, as a Network Customer, shall be required to designate resources and loads on behalf of its Native Load Customers, in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transmission capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service: The Transmission Provider will provide firm transmission service over its Transmission System to all Network Customers for the delivery of capacity and energy from designated Network Resources on a basis that is comparable to the Transmission Provider's historical use of the Transmission System to reliably serve its Native Load Customers.

33.2 Transmission Constraints: During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources.

33.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, all Network Customers, including network service taken by the Transmission Provider on behalf of its Native Load Customers, will bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.5 Allocation of Curtailments: The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by all Network Customers, including the Transmission Provider on behalf of its Native Load Customers in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.7 System Reliability: Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

In addition, the Commission proposes to require Transmission Providers to make the following changes to section 2 of the pro forma tariff:

2. Reservation Priority for Existing Firm Service Customers

2.1 Right of First Refusal: Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer.

2.2 Notice of Rollover: Consistent with requests for new service described in Section 13.2 of Part II of the Tariff, a Transmission Customer must submit its request to exercise rollover rights no later than sixty (60) days prior to the date the current service agreement expires.

2.3 Future Load Growth: The Transmission Provider may reserve existing transmission capacity needed for future load growth reasonably forecasted within the Transmission Provider's current planning horizon. The Transmission Provider may decline a Customer the ability to roll over its firm transmission service with a term of one year or longer only if the Transmission Provider includes in the original service agreement a specific, reasonably forecasted need for the transfer capability to serve load growth at the end of the term of the service agreement.

2.4 Redirects: A Customer receiving firm transmission service with a term of one year or longer which requests to use alternate point(s) of receipt or delivery retains its right of first refusal for service the original point(s) of receipt and delivery at the time the current service agreement expires.

Appendix B—SMD Tariff

Standard Market Design Pro Forma Open Access Transmission Tariff Table of Contents

Part I. General Term and Conditions

A. Common Service Provisions

1. Definitions

Access Charge: A charge designed to recover the embedded costs of the Transmission System.

Ancillary Services: Those services that are necessary to support the transmission of Energy from Resources to Loads while maintaining reliable operation of the Independent Transmission Provider's Transmission System in accordance with Good Utility Practice.

Automatic Generation Control (''AGC''): The automatic regulation of the power output of electric generating facilities within a prescribed range in response to a change in system frequency, or tie-line loading, to maintain system frequency or scheduled interchange with other areas within predetermined limits.

Availability Bid: Bid by a Resource that indicates the minimum price at which Regulation or Operating Reserves is offered to be supplied.

Available Transfer Capability (''ATC''): A measure of the Transfer Capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability, less the sum of existing transmission commitments (including transmission which is used for reliability purposes).

Base Point Signal: Signals sent from the Independent Transmission Provider and ultimately received by Resources specifying the scheduled MW level for the Resource.

Bid: Offer to purchase and/or sell products or services in an Auction, including Energy, Demand Reductions, Transmission Service, Congestion Revenue Rights and/or Ancillary Services at a specified location, quantity, and time-period that is duly submitted to the Independent Transmission Provider pursuant to Independent Transmission Provider Procedures. The Bid should indicate either a specific price or the Bidder's desire to have the Bid accepted regardless of the market clearing price.

Bid Revenue Sufficiency Guarantee: A guarantee by the Independent Transmission Provider that ensures the minimum recovery of the Bid prices for Resources scheduled through the Day-Ahead Market, in subsequent post Day-Ahead Market commitments for reliability, and in the Real-Time Market.

Bilateral Transaction Schedule: Simultaneous schedules of Load and Generation of the same MW level by a Market Participant.

Boundary Interface: Point(s) used to indicate Point(s) of Receipt and Point(s) of Delivery outside of the Service Area.

Commission (''FERC''): The Federal Energy Regulatory Commission, or any successor agency.

Completed Application: An application for Transmission or Market Service that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Congestion: The state of a Transmission System when a binding limit (constraint) on the system's Transfer Capability is reached that must be addressed.

Congestion Charges: Charges relating to the Marginal Congestion Component of Energy Purchases or Transmission Usage Charges. These charges reflect the increased cost that result from dispatching the Transmission System to respect Transmission System (or Flowgate) constraints.

Congestion Revenue Deficit: In the Day-Ahead Market, the absolute value of the difference between the Hourly Congestion Charge Collection and the Hourly Net Congestion Revenue Owed to Congestion Revenue Rights Holders when the difference is negative.

Congestion Revenue Right: A property right held by a Customer that entitles and/or obligates the holder of the right to receive specified Congestion revenues.

Congestion Revenue Surplus: In the Day-Ahead Market, the difference between the Hourly Congestion Charge Collection and the Hourly Net Congestion Revenue Owed to Congestion Revenue Rights Holders when the difference is positive.

Contingency: An actual or potential unexpected failure or outage of a system component, such as a Generator, transmission line, circuit breaker, switch or other electrical element. A Contingency also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Center: The equipment, facilities and personnel used by the Independent Transmission Provider to coordinate and direct the operation of the Service Area and to administer the Day-Ahead and Real-Time Markets, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the Day-Ahead and Real-Time Markets or the operation of the Service Area.

Curtailment: Reduced transmission service or provision of electricity to a Customer in response to a transmission capability for reliability purposes.

Customer: An entity which has complied with the requirements contained in this Tariff, including having signed a Service Agreement, and is eligible to utilize the services provided by the Independent Transmission Provider under this Tariff; provided, however, that a party taking services under this Tariff pursuant to an unsigned Network Access Service Agreement filed with the Commission by the Independent Transmission Provider shall be deemed a Customer.

Day-Ahead: Nominally, the twenty-four hour period directly preceding the Operating Day, except when this period may be extended by the Independent Transmission Provider to accommodate holidays and weekends.

Day-Ahead Market: The market administered by the Independent Transmission Provider in which Energy, Ancillary Services, and Transmission Services are scheduled and sold Day-Ahead, consistent of the Day-Ahead scheduling process, price calculations, and settlements.

Decremental Energy Bid: A Bid Price curve provided by an entity engaged in a bilateral Import or Internal Transaction to indicate the LMP below which that entity is willing to reduce its Generator's output and purchase Energy in the LMP Markets.

Delivering Party: The entity supplying capacity and Energy to be transmitted at Point(s) of Receipt.

Delivery Point: The location where a transaction terminates. A Delivery Point can be a delivery Node, an aggregation of delivery Nodes, an Interface, or a Trading Hub. For purposes of this Tariff, the Delivery Point does not have to be a location where power is consumed.

Direct Assignment Facilities: Facilities or portions of facilities that are constructed for the sole use/benefit of a particular Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Customer and shall be subject to Commission approval.

Dispatch Hour: The sixty (60) minute period commencing at the beginning of each hour (0000 hour).

Dispatch Interval: Length of time between dispatch instructions from the Independent Transmission Provider.

Emergency: Any abnormal system condition that requires immediate automatic or manual action to prevent or limit loss of transmission facilities or Generators that could adversely affect the reliability of the electric system.

Energy: A quantity of electricity that is Bid, produced, purchased, consumed, sold or transmitted over a period of time and measured or calculated in megawatt-hours.

Energy Bid: For an Energy Supplier, a Bid curve that indicates an entity's willingness to supply Energy at certain prices to markets operated by the Independent Transmission Provider. For an Energy Purchaser, Bid curve that indicates an entity's willingness to purchase Energy at certain prices in markets operated by the Independent Transmission Provider.

Energy Limited Resource: Capacity Resources that, due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, are unable to operate continuously on a daily basis.

Ex Ante Real-Time Energy LMP: The LMP that is produced by the Independent Transmission Provider's Security Constrained Dispatch and communicated to Resources under dispatch instructions in advance of real time. Under SMD, the LMP used for settlement is the Ex Post LMP.

Ex Post Real-Time Energy LMP: The LMP that is produced following the evaluation of actual dispatch relative to dispatch instructions. It is the LMP used for settlement purposes in the Real-Time Market.

Existing Transmission Contract: A contract for Transmission Service or wholesale requirements service currently in effect between two or more Transmission Owners, or between a Transmission Owner and another entity, that was executed on or before July 9, 1996, or earlier.

Export: Energy that is delivered from the Independent Transmission Provider Service Area Interconnection to another Service Area.

External Transaction: A Bilateral Transaction in which either the Receipt Point or the Delivery Point must be a point at the boundary of the Independent Transmission Provider Service Area. If the Receipt Point is a Boundary Interface, then the External Transaction is an Import. If the Delivery Point is a Boundary Interface, then the External Transaction is an Export.

Facilities Study: An engineering study conducted by the Independent Transmission Provider to determine the required modifications to the Independent Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

Federal Power Act (''FPA''): The Federal Power Act, as may be amended from time-to-time (See 16 U.S.C. § 796 et seq.)

Fixed Block Resource: A unit that, due to operational characteristics, can only be in one of two states: either turned completely off, or turned on and run at a fixed capacity level.

Flowgate: A transmission facility (such as a transmission line or a transformer or some other component of the electrical network) or group of facilities (*e.g.,* an Interface).

Flowgate Right: A Congestion Revenue Right specified by a portion of the total MW capacity over a particular transmission Flowgate in a specified direction. Flowgate Rights entitle the holder to collect congestion revenues associated with the specified MW flow over the identified Flowgate in the specified direction.

Generation Capacity: The sustained maximum net output of a Generator, measured in megawatts, as demonstrated by the performance of a test or through actual operation as defined in the Independent Transmission Provider Procedures.

Generator: A facility capable of supplying Energy, capacity and/or Ancillary Services that is accessible to the Service Area.

Good Utility Practice: 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. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Hourly Economic Maximum Level: The maximum MW level a Resource may operate under normal system conditions.

Hourly Economic Minimum Level: The minimum MW level a Resource may operate under normal system conditions.

Hourly Emergency Maximum Level: The maximum MW level a Resource may operate under Emergency system conditions.

Hourly Emergency Minimum Level: The maximum MW level a Resource may operate under Emergency system conditions.

Hub: A mathematical simplification of a set of buses to emulate a single bus for financial and trading purposes. A Hub is defined by a set of buses that are each associated with a fixed numerical weights such that the sum of weights equal one.

Hub Price: The weighted average of Energy LMP's at the buses that comprise the Hub.

Import: Energy that is delivered to an Independent Transmission Provider Service Area Interconnection from another Service Area.

Incremental Energy Bid: A Bid Price curve for Energy generated above the Hourly Minimum Economic Level.

Independent Transmission Provider: The entity that operates the facilities used for the transmission of Energy in interstate commerce and provides transmission service under the Tariff.

Independent Transmission Provider's Monthly Transmission System Peak: The maximum usage of the Independent Transmission Provider's Transmission System in a calendar month.

Interface: A defined set of transmission facilities (see also Boundary Interface).

Internal Transaction: Bilateral Transactions whose Receipt Point and Delivery Point are both within the Independent Transmission Provider's service territory.

Load: A term that refers to either a consumer of Energy or the amount of Energy (MWh) or demand (MW) consumed.

Load Forecast: Independent forecasts by the Independent Transmission Provider of Load within the Independent Transmission Provider's Service Area used in its scheduling decisions to ensure reliable operation of the system.

Load Ratio Share: The ratio of a Load-Serving Entity's Load to total Load within the Service Area during a specified time period.

Load-Serving Entity: An entity, including a municipal electric system and an electric cooperative, authorized by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, to retail Customers located within the Independent Transmission Provider's Service Area, including an entity that takes service directly from the Independent Transmission Provider to supply its own Load in the Independent Transmission Provider's Service Area.

Load Shedding: The systematic reduction of system demand by temporarily decreasing Load in response to Transmission System or area capacity shortages, system instability, or voltage control considerations.

Locational Marginal Pricing (''LMP''): A pricing methodology under which the price of Energy at each location in the Transmission System is equivalent to the cost to supply or the value to purchase the next increment of Load at that location taking into account the physical aspects of the Transmission System. The term LMP also refers to the price of Energy bought or sold at a specific location.

Lower Regulation Limit: The lowest operating point that the Independent Transmission Provider may dispatch a unit for Regulation under normal operating conditions.

Marginal Congestion Component (''MCC''): Component of Locational Marginal Price and Transmission Usage Charge reflecting the cost of dispatching the Resources available to the Independent Transmission Provider such that transmission constraints are respected.

Marginal Loss Charge Collection: The net amounts charged to purchasers associated with the Marginal Loss Component of the hourly LMPs at the purchasers' buses less the net amounts paid to sellers associated with the Marginal Loss Component of the hourly LMPs at the sellers' buses.

Marginal Losses: The Transmission System Real Power Losses associated with each additional MWh of consumption by Load, or each additional MWh transmitted under a Bilateral Transaction as measured at the Points of Withdrawal.

Marginal Losses Component (''MLC''): The component of LMP at a bus that accounts for the Marginal Losses, as measured between that bus and the Reference Bus.

Market Clearing Price: The price of a product or service determined by the Independent Transmission Provider at a given location and time at which the total amounts offered for sale and purchase are equal.

Market Monitor(ing Unit): Entity required to report directly to the Commission and to the independent governing board of the Independent Transmission Provider the results and recommendations derived from its study of the markets operated by the Independent Transmission Provider.

Market Services: Services provided by the Independent Transmission Provider under the Tariff related to the markets for Energy, capacity and Ancillary Services.

Maximum Curtailment Time: Maximum time (in hours) that a supplier of demand response Resources is willing to respond to Curtailment dispatch instructions.

Maximum Run Time: Maximum length of time (in hours) that a Generator can be reliably expected to operate.

Maximum Shut Down Limit: Maximum number of times a Generator is able to shut down in a 24 period.

Maximum Start-up Limit: Maximum number of times a Generator is able to start-up in a 24 period.

Minimum Curtailment Time: Minimum time (in hours) that a supplier of demand response Resources is willing to respond to Curtailment dispatch instructions.

Minimum Down Time: Minimum length of time (in hours) required for a Generator to begin operations following an outage due to operational constraints.

Minimum Generation Bid: The payment required by a Supplier to operate at the unit's Hourly Economic Minimum.

Minimum Generation Emergency: An Emergency declared by the Independent Transmission Provider in which the Independent Transmission Provider anticipates requesting one or more generating Resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Run Time: Minimum length of time (in hours) required for a Generator to be in operation due to operational constraints.

Network Access Service: Transmission service offered by the Independent Transmission Provider under this Tariff. It offers use of the transmission grid by allowing Customers to: (1) Serve Load with any Resource on the system, (2) access any Interface to import power from a neighboring system, (3) integrate, economically dispatch and regulate its current and planned Resources to serve its Load; (4) transmit power through and out of the Independent Transmission Provider's system, and (5) aggregate Resources for resale and hub-to-hub transfer.

Network Operating Agreement: Agreement that contains the terms and conditions under which the Customer shall operate its facilities and the technical and operational matters associated with the implementation of the Tariff.

Network Operating Committee: Committee responsible for coordinating operating criteria to determine each Party's responsibilities under the Network Operating Agreement.

No-load Cost: Hourly costs associated with generating at a unit's Hourly Economic Minimum.

Node: A location where Energy can be injected and/or withdrawn from the grid.

Normal Response Rate: The expected response rate of an Energy supplying Resource measured in MW/min.

Obligation Right: A Congestion Revenue Right that requires the Customer to receive the Congestion revenues (either positive or negative).

Open Access Same-Time Information System (OASIS): The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Operable Capacity: Capacity that is readily converted to Energy and is measured in MW.

Operating Day: The daily 24 hour period beginning at midnight for which transactions on the Energy Market are scheduled.

Operating Reserves: Generator Capacity that is available to supply Energy, or Load Resources that are available to Curtail Energy usage, in the event of Contingency conditions, which meet the requirements of the Independent Transmission Provider. Operating Reserves include Spinning Reserves and Supplemental Reserves.

Opportunity Cost: The cost of giving up the opportunity to sell (or consume) a product (or service) at a location and time in order to sell a related product (requiring the same inputs), at the same location and time or the same product at another location and time.

Optimal Power Flow (''OPF''): A Power Flow that maximizes the value (as expressed in the Bids) of the Congestion Revenue Rights, subject to the constraint that the selected set of Bids must be simultaneously feasible.

Option Right: A Congestion Revenue Right that allows the Customer to receive the positive Congestion revenues without the obligation to pay Congestion revenues when they are negative.

Planning Horizon: The number of years ahead in each region for which the Load-Serving Entities must demonstrate to the Independent Transmission Provider that they have procured adequate Energy Resources.

Power Flow: A simulation tool that provides an estimate of Energy flows on the Transmission System and adjacent transmission systems under a given set of assumed characteristics.

Primary Holder: The Owner of a Congestion Revenue Right recognized as such by the Independent Transmission Provider for settlement purposes.

Real Power Losses: The loss of Energy, resulting from transporting power over the Transmission System, between the Point of Injection and Point of Withdrawal of that Energy.

Real Time: Referring to the time period in which transmission and generation dispatch instructions are ultimately given.

Real-Time Market: The market administered by the Independent Transmission Provider for Energy, Ancillary Services, and Transmission Services in real time, consisting of the real time scheduling process, dispatch, price calculations, and settlements.

Receipt Point: The location where a Transaction originates. A Receipt Point can be a Generator Node, an aggregation of Generator Nodes, an Interface, or a Trading Hub. For purposes of this Tariff, a Receipt Point does not have to be a Generator.

Receipt Point-to-Delivery Point Congestion Revenue Right Obligation: Congestion Revenue Rights that confer: (i) The right to collect revenues equal to the applicable Marginal Congestion Component of the hourly Transmission Usage Charge from the Receipt Point to the Delivery Point when the Marginal Congestion Component is positive, and (ii) the obligation to pay an amount to the Independent Transmission Provider equal to the absolute value of the applicable Marginal Congestion Component of the hourly Transmission Usage Charge when the Marginal Congestion Component is negative.

Receipt Point-to-Delivery Point Congestion Revenue Right Option: Congestion Revenue Rights that confer to the holder the right to collect revenues equal to the applicable Congestion Charge component of the hourly Transmission Usage Charge from the Receipt Point to the Delivery Point when the Marginal Congestion Component is positive, but do not obligate the holder to pay the absolute value of the applicable Marginal Congestion Component of the hourly Transmission Usage Charge when the Marginal Congestion Component is negative.

Receiving Party: The entity receiving the capacity and Energy transmitted by the Independent Transmission Provider to Point(s) of Delivery.

Reference Bus: The location on the Transmission System relative to which all mathematical quantities, including Shift Factors and penalty factors relating to physical operation, will be calculated.

Regulation: The capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the Manuals. Regulation also encompasses regulation and frequency response service i.e. the continuous balancing of Resources (generation and interchange) with Load variations in order to maintain scheduled Interconnection frequency.

Regulation Capability: The maximum amount of Regulation Service in MW a Resource can operationally provide to the Independent Transmission Provider.

Regulation Requirement: Quantity of Regulation identified by the local reliability authority to be procured by the Independent Transmission Provider to ensure system reliability.

Reliability Rules: Those rules, standards, procedures and protocols, including Local Reliability Rules, developed in accordance with NERC, regional reliability councils, FERC, PSC and NRC standards, rules and regulations, and other criteria.

Reserve Location: Geographic area for which there is a specific Operating Reserve requirement applies.

Resource: Either a Generator or a Load that can reliably adjust its electricity usage by some specified range and rate at a specific Withdrawal Point in response to Day-Ahead or Real-Time prices or by instruction by the Independent Transmission Provider.

Resource Adequacy Requirement: The Resource reserve margin, stated as a ratio of the reserves to the forecast peak load during the final year of the Planning Horizon, expressed as a percentage.

Response Rate: The capability (in MW/minute) of a Resource to adjust its generation level in response to dispatch signals.

Scheduled Amount: Megawatt supply or demand obligation as indicated by the Independent Transmission Provider's Schedule.

Scheduled Resource: Resource incurring a supply or demand obligation as indicated by the Independent Transmission Provider's Schedule.

Security Constrained Dispatch: The determination of the dispatch that incorporates all transmission constraints necessary for reliability.

Security Constrained Unit Commitment: The allocation of Load to Generators by the Independent Transmission Provider through the operation of a computer algorithm which continuously calculates individual Generator loading at minimum Bid cost, balancing Load and scheduled interchange with generation while meeting all reliability rules and Generator performance constraints.

Self-Schedule: The Supplier's provision to the Independent Transmission Provider with its hourly Energy schedule in the Day-Ahead Market and Real-Time Market independent of market prices.

Self-Supply: The provision of certain Ancillary Services, or the provision of Energy to replace Marginal Losses, by a Customer using either the Customer's own Generators or generation obtained from an entity other than the Independent Transmission Provider.

Seller: Market Participant whose Bid to supply into either the Day-Ahead or Real-Time Market has been accepted and who has incurred the associated supply obligations.

Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Customer and the Independent Transmission Provider for service under the Tariff.

Service Area: The geographic region and transmission facilities therein that are under the operational control of the Independent Transmission Provider.

Service Commencement Date: The date the Independent Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Independent Transmission Provider begins to provide service in accordance with the Tariff.

Settlement: The process of determining the charges to be paid to or by a Customer in the markets operated by the Independent Transmission Provider under this Tariff.

Shift Factor: A ratio, calculated by the Independent Transmission Provider, that compares (1) the change in power flow through a transmission facility resulting from an incremental change in injection of power at a Receipt Point and withdrawal of power at the Delivery Point to (2) the incremental change in injection of power at the Receipt Point.

Shortage: A situation in which the markets for Energy, Regulation or Operating Reserves are not able to clear because of insufficient Bid-in capacity.

Spinning Reserves: Operating Reserves provided by synchronized Resources that can respond immediately to dispatch instructions.

Spinning Reserves Requirement: Quantity of Spinning Reserves identified by the local reliability authority to be procured by the Independent Transmission Provider to ensure system reliability.

Start Time: The number of hours required by a generating Resource to reach its Hourly Economic Minimum Level.

Start-up Cost: Payment needed by the Purchaser of Energy to cover the fixed costs associated with its Energy Bid or payment required by Generator to Start-up and reach its minimum operating level.

Supplemental Commitment: Scheduling of Resources by the Independent Transmission Provider following the posting of the Day-Ahead Schedule to meet the reliability needs.

Supplemental Reserves: Operating Reserves provided by Resources that can be started, synchronized and loaded within a specified time period.

Supplemental Reserves Requirement: Quantity of Supplemental Reserves identified by the local reliability authority to be procured by the Independent Transmission Provider to ensure system reliability.

Supplier: A Party that is supplying the Demand Reduction, Energy and/or associated Ancillary Services to be made available under the Tariff, including Generators and demand side Resources that satisfy all applicable Independent Transmission Provider requirements.

System Impact Study: An assessment by the Independent Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for Congestion Revenue Rights or (ii) whether any additional costs may be incurred in order to provide Congestion Revenue Rights.

System Marginal Price (SMP): The LMP of Energy at the Reference Bus.

Total Transfer Capability: The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner.

Transaction: The purchase and/or sale of Energy, Congestion Revenue Rights, Ancillary Services, or Transmission Service.

Transfer Capability: The measure of the ability of interconnected electrical systems to reliably move or transfer power from a set of Receipt Points to a set of Delivery Points over all transmission facilities (or paths) between those areas under specified system conditions.

Transmission Owner: Entity with financial ownership of the transmission assets used in the provision of Transmission Service by the Independent Transmission Provider.

Transmission Owner's Monthly Transmission System Peak: The maximum hourly firm usage as measured in megawatts (MW) of the Transmission Owner's transmission system in a calendar month.

Transmission Planned Outage: Any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified by the Independent Transmission Provider.

Transmission Service: Services needed to move Energy from a Receipt Point to a Delivery Point provided to Customers by the Independent Transmission Provider in accordance with this Tariff.

Transmission System: The facilities controlled and operated by the Independent

Transmission Provider that are used to provide transmission service under the Tariff.

Transmission Usage Charge: A per unit charge for Transmission Service to support a Bilateral Transaction. The Transmission Usage Charge is equal to the difference of the LMP at the Delivery Point and the LMP at the Receipt Point (in $/MWh).

Unit-Specific Opportunity Cost: The Opportunity Cost calculation for specific Resources that are selected to provide Regulation or Operating Reserves in either the Day-Ahead or the Real-Time Markets.

Upper Regulation Limit: The highest operating point that the Independent Transmission Provider will dispatch a unit for Regulation under normal operating conditions.

Virtual Demand Bid: A Demand Bid in the Day-Ahead Market without a physical Resource capable of withdrawing Energy in the Real-Time Market.

Virtual Energy: Energy purchased or sold in the Day-Ahead Energy Market that is not backed by physical Resources.

Virtual Supply Bid: A Supply Bid in the Day-Ahead Market without a physical Resource capable of injecting Energy in the Real-Time Market.

Voltage Support Service: The provision of reactive power support necessary to maintain transmission voltage.

Wheel Through: Transmission Service through the Service Area of the Independent Transmission Provider that originates and terminates outside the Service Area of the Independent Transmission Provider.

Zonal-LMP: Load weighted average of Energy LMPs over a set of buses and weights defined by a zone.

Zone: A set of buses in a geographic area.

Zone Price: Load weighted average price over the defined set of buses in a zone.

2. Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR § 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities).

3. Local Furnishing Bonds

3.1 Transmission Owners That Own Facilities Financed by Local Furnishing Bonds: This provision is applicable only to Transmission Owners that have financed facilities for the local furnishing of Energy with tax-exempt bonds, as described in section 142(f) of the Internal Revenue Code of 1986, as amended, or corresponding provisions of predecessor statutes (''local furnishing bonds''). Notwithstanding any other provision of this Tariff, the Independent Transmission Provider shall not be required to provide transmission service to any Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) used, in whole or in part, to finance the Transmission Owner's facilities, regardless of whether such facilities financed with these bonds are transmission, distribution, or generation facilities.

3.2 Alternative Procedures for Requesting Transmission Service:

(i) If the Independent Transmission Provider determines that the provision of transmission service requested by a Customer would jeopardize the tax-exempt status of any outstanding local furnishing bond(s) used, in whole or part, to finance any of the Transmission Owner's facilities, regardless of whether such facilities financed with these bonds are transmission, distribution, or generation facilities, or would jeopardize the Transmission Owner's entitlement to income tax deductions for interest expense in connection with such tax-exempt bonds, it shall advise the Customer within thirty (30) days of receipt of the Completed Application of (a) such determination and (b) the reasonably expected amount of any costs resulting from such loss of tax-exempt status and/or income tax deductions (or from the prevention of any such loss). For purposes of this section, the costs resulting from such loss of tax exempt status and/or income tax deductions (or from the prevention of any such loss) due to the provision of such transmission service shall include, without limitation, any reasonable transactions costs (including any redemption premium) of defeasing and/or redeeming any outstanding local furnishing bonds and/or from any such refinancing with taxable debt and/or from any disallowance or loss of a deduction for tax purposes of the interest in respect of such bonds.

(ii) If the Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Independent Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Independent Transmission Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act specifying that such service is provided subject to the Customer's payment of all costs deemed by the Commission to be eligible for recovery under Section 212(a) of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Independent Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff and such order. Transmission service shall not commence until after the Customer complies with the creditworthiness provisions of Section 8 of this Tariff.

4. Reciprocity

A Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing on similar terms and conditions over facilities used for the transmission of Energy owned, controlled or operated by the Customer and over facilities used for the transmission of Energy owned, controlled or operated by the Customer's corporate affiliates. A Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of Energy owned, controlled or operated by the Customer and over facilities used for the transmission of Energy owned, controlled or operated by the Customer's corporate affiliates.

This reciprocity requirement applies not only to the Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist a Customer to avoid the requirements of this provision.

5. Billing and Payment

5.1 Billing Procedure: Within a reasonable time after the first day of each month, the Independent Transmission Provider shall submit an invoice to the Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Independent Transmission Provider, or by wire transfer to a bank named by the Independent Transmission Provider.

5.2 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 CFR § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Independent Transmission Provider.

5.3 Customer Default: In the event the Customer fails, for any reason other than a billing dispute as described below, to make payment to the Independent Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Independent Transmission Provider notifies the Customer to cure such failure, a default by the Customer shall be deemed to exist. Upon the occurrence of a default, the Independent Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Independent Transmission Provider and the Customer, the Independent Transmission Provider will continue to provide service under the Service Agreement as long as the Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Customer fails to meet these two requirements for continuation of service, then the Independent Transmission Provider may provide notice to the Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

6. Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the jurisdictional Independent Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

7. Force Majeure and Indemnification

7.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Independent Transmission Provider nor the Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

7.2 Indemnification: The Customer shall at all times indemnify, defend, and save the Independent Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Independent Transmission Provider's performance of its obligations under this Tariff on behalf of the Customer, except in cases of negligence or intentional wrongdoing by the Independent Transmission Provider.

8. Creditworthiness

For the purpose of determining the ability of the Customer to meet its obligations related to service hereunder, the Independent Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Independent Transmission Provider may require the Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Customer and acceptable to the Independent Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Independent Transmission Provider against the risk of non-payment.

9. Eligibility for Independent Transmission Provider Services

In order to purchase Network Access Service, purchase or supply Energy, or to supply Ancillary Services in the Independent Transmission Provider Administered Markets, Customers must satisfy the requirements of this Article.

9.1 Requirements for Network Access Service: A Customer eligible for Network Access Service is: (i) any electric utility (including the Load-Serving Entity or any power marketer), Federal power marketing agency, or any person generating Energy for sale is eligible to be a Customer for Network Access Service under the Tariff. Energy sold or produced by such entity may be Energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Independent Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Independent Transmission Provider. (ii) Any retail Customer taking unbundled transmission service pursuant to a state requirement that the Independent Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Independent Transmission Provider, is eligible to be a Customer under the Tariff.

9.2 Requirements for Market Services: The Independent Transmission Provider and each market participant shall execute a Service Agreement for Market Services which sets forth the terms and conditions under which a market participant shall either supply or purchase market services, consistent with the Form of Service Agreement for Market Services in Part VII.

9.3 Participating Generator Agreements: The Independent Transmission Provider and the owners of each Generator shall enter into a Participating Generator Agreement which shall be filed with the Commission. Each Participating Generator Agreement shall set forth the operating terms, conditions, and obligations concerning the dispatch of a generating unit.

9.4 Requirements Common to All Customers: Completed Application and Minimum Technical Requirements

A Customer shall submit a Completed Application and shall receive Independent Transmission Provider approval prior to obtaining any services under the Independent Transmission Provider's Tariff. A Customer also shall demonstrate to the Independent Transmission Provider's reasonable satisfaction that it is capable of performing all functions required by the Independent Transmission Provider's Tariff including operational, financial and settlement requirements.

9.4.1 Application: Each Customer requesting to schedule, take or provide any services under the Tariff must apply to the Independent Transmission Provider in writing at least sixty (60) days in advance of the month in which service is to commence. The Independent Transmission Provider will consider requests for such services on shorter notice when feasible. Service commencement will depend on the Independent Transmission Provider's ability to accommodate the request. To apply, the Customer shall complete and deliver a Service Agreement (in the form of Part VII) and an Application to the Independent Transmission Provider.

9.4.2 Completed Application: A Completed Application shall provide all of the information reasonably required by the Independent Transmission Provider to permit the Independent Transmission Provider to perform its responsibilities under the Independent Transmission Provider's Tariff. A Customer taking or providing service under the Tariff shall provide the Independent Transmission Provider, upon application for service, with a list identifying its parent company as well as any affiliate. The Customer shall notify the Independent Transmission Provider within 30 days of the effective date of any change to the original list. Any Customer shall notify the Independent Transmission Provider within 30 days of the effective date of any change to the original list. Any Customer shall respond within 10 days to a request by the Independent Transmission Provider to update the list of affiliates and/or parent company. The Independent Transmission Provider shall treat the information provided in the Application as Confidential Information except to the extent that disclosure of the information is required by the Independent Transmission Provider's Tariff, by regulatory or judicial order or for reliability purposes pursuant to Good Utility Practice.

9.4.3 Approval of Application and/or Notice of Deficient Application:

The Independent Transmission Provider will promptly review the Application and may request additional information to determine whether the applicant meets the Independent Transmission Provider's minimum financial and technical requirements. The Independent Transmission Provider will notify the applicant within thirty (30) days of receipt of a Completed Application.

If the Independent Transmission Provider rejects an Application, the Independent Transmission Provider shall provide a written explanation within fourteen (14) days of the rejection. The Independent Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the applicant. If such efforts are unsuccessful, the Independent Transmission Provider shall return the Application.

10. Dispute Resolution Procedures

10.1 Internal Dispute Resolution Procedures: Any dispute between a Customer and the Independent Transmission Provider involving transmission or Market Services under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Independent Transmission Provider and a senior representative of the Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

10.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

10.3 Arbitration Decisions: Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

10.4 Costs: Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(A) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(B) one half the cost of the single arbitrator jointly chosen by the Parties.

10.5 Rights Under the Federal Power Act: Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

11. Metering

11.1 Customer Requirements: The Independent Transmission Provider shall establish metering specifications and standards for all metering that is used as a data source by the Independent Transmission Provider. Customers shall install and maintain such metering at their own expense and deliver data to the Independent Transmission Provider without charge. A Customer taking service under the Independent Transmission Provider's Tariff will make available to the Independent Transmission Provider metered data that meets Independent Transmission Provider requirements by one of the following means: (i) Direct transmission to the Independent Transmission Provider; (ii) direct transmission to the Independent Transmission Provider through Transmission Owner communications equipment, or (iii) indirectly through metering provided by the Transmission Owner within whose area its Load is located. The Customer also shall provide its metered data to the Transmission Owner within whose area its Load is located, to the extent that the Transmission Owner determines that the metered data provided to the Independent Transmission Provider is required for its system operation and planning functions, for the billing of services it provides to the Customer, or to perform calculations required by the Independent Transmission Provider.

11.2 Load-Serving Entities: Any Load that is not directly metered, as described above, will have its Load determined by the Transmission Owner within whose area its Load is located in accordance with the Transmission Owner's Retail Access plan on file with the (state commission) or otherwise authorized.

11.3 Ancillary Service Suppliers: Suppliers shall ensure that adequate metering data is made available to the Independent Transmission Provider as described above.

11.4 Third Party Metering Services: Customers whose metering services are provided by third parties qualified under rules, regulations and procedures of applicable state regulatory authorities shall be responsible to ensure that all data described in this Section are satisfactorily made available to the Independent Transmission Provider and applicable Transmission Owner(s) by those third parties.

11.5 Estimation of Metering: In the event of a meter malfunction or inadequate metering data, the Independent Transmission Provider may use estimates to determine Customer's rights and responsibilities under the Independent Transmission Provider's Tariff.

12. Data and Confidentiality Provisions

12.1 Access to Complete and Accurate Data: Customers under the Tariff shall provide to the Independent Transmission Provider such information and data as the Independent Transmission Provider reasonably deems necessary in order to perform its functions and fulfill its responsibilities under the Tariff and in accordance with the Independent Transmission Provider Market Monitoring Program. Such information will be provided on a timely basis and in the formats prescribed in the Independent Transmission Provider Procedures.

12.2 Independent Transmission Provider Procedures: The Independent Transmission Provider shall develop, and modify as appropriate, procedures for the efficient and non-discriminatory operation of the Independent Transmission Provider Administered Markets and for the safe and reliable operation of the Independent Transmission Provider's Service Area in accordance with the terms and conditions of the Tariff. All such procedures must be consistent with Good Utility Practice. Whenever requested by the Independent Transmission Provider, each Load-Serving Entity shall provide the Independent Transmission Provider with a forecast of the Loads for which it is responsible for the particular time period designated by the Independent Transmission Provider. Customers shall inform the Independent Transmission Provider of the Availability of Generators within the Independent Transmission Provider Service Area subject to a Customer's control by Energy contract, ownership or otherwise. Additionally, the Transmission Owners will provide megawatt, megavar, voltage readings, Transmission System data (facility ratings and impedance data), and maintenance schedules for all Transmission Facilities under the Independent Transmission Provider's Operational Control. For Transmission Facilities Requiring Independent Transmission Provider Notification, the Transmission Owners shall inform the Independent Transmission Provider of all changes in the status of the designated transmission facilities. Suppliers will provide data on Generator status and output including maintenance schedules, Generator scheduled return dates (inclusive of return to service from maintenance, forced outages or partial unit outages that resulted in a significant reduction in a generating unit's ability to produce Energy in any hour), and Generator machine data. These data shall also include Generator Incremental/Decremental Bids, operating limits, response rates, megawatt, megavar, and voltage readings.

12.3 Access to Confidential Information: The Independent Transmission Provider may request, and the Customer shall provide, Confidential Information consistent with the disclosure requirements set forth in the Independent Transmission Provider's Tariff. The Independent Transmission Provider shall prevent the disclosure of Confidential Information and shall not publish, disclose or otherwise divulge Confidential Information to any person or entity without the prior written consent of the party supplying such Confidential Information, except as provided for under the Independent Transmission Provider Market Power Monitoring Plan. The provisions of this Section shall not apply to any Confidential Information: (i) Which was in the public domain at the time of disclosure hereunder; (ii) which thereafter passes into the public domain by acts other than the acts of the Independent Transmission Provider; (iii) that the Independent Transmission Provider is required to make publicly available by the Commission, the (state commission) or other legal process, or for reliability purposes pursuant to Good Utility Practice; or (iv) information required to be provided to the Commission, which will be protected under the Commission's rules for non-public material. A Customer may request that the Independent Transmission Provider keep confidential from another entity Confidential Information that the other entity does not require to perform its obligations and duties hereunder. The Customer must state in writing that the information is to be treated as Confidential Information and the reasons for treating it as Confidential Information, otherwise information will be treated as non-Confidential Information.

12.4 Use of Confidential Information: The Independent Transmission Provider shall use Confidential Information for the exclusive purpose of performing its obligations hereunder and under any Service Agreement.

12.5 Disclosure of Bid Information: Pursuant to Commission requirements, the Independent Transmission Provider shall make public Bid information from the Energy, Ancillary Services, and Transmission markets (but not the names of the Bidders making these Bids) three months after the Bids are submitted. The Independent Transmission Provider shall post the data in a way that permits third parties to track each individual Bidder's Bids over time. Prior to such disclosure, Bid information submitted to the Independent Transmission Provider by Market Participants shall be considered Confidential Information.

12.6 Survival: This section 12 will survive the termination of the Independent Transmission Provider's Tariff and any associated Service Agreement.

Part II. Transmission Services

B. Network Access Service

Preamble

The Independent Transmission Provider will provide Network Access Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Access Service allows all Customers to access all points (*i.e.*, all Receipt Points and all Delivery Points on the Independent Transmission Provider's system) so that every Generator can reach every Load, subject to physical feasibility. Specifically, Network Access Service offers a flexible use of the transmission grid by allowing Customers to: (1) Serve Load with any Resource on the system, (2) access any Interface to import power from a neighboring system, (3) integrate, economically dispatch and regulate its current and planned Resources to serve its Load; (4) transmit power within, through, and out of the Independent Transmission Provider's system; and (5) aggregate Resources for resale and hub-to-hub transfer.

1. Nature of Network Access Service

1.1 Scope of Service: Network Access Service allows all Customers to access all points (*i.e.*, all Receipt Point and Delivery Points) on the Independent Transmission Provider's system so that every Customer can move power from any Generator to any Load, from any Generator to any Trading Hub, from one Trading Hub to another, or from a Trading Hub to a Load. Using Network Access Service, a Customer can integrate Resources and Load, transfer power through or out of the Independent Transmission Provider's system or deliver power between specified Receipt and Delivery Points. The embedded costs of the Transmission System will be recovered through an Access Charge. Any Congestion costs and loss costs associated with a transaction will be recovered through the applicable Transmission Usage Charge in which the Customer causing the Congestion and losses bears the full cost of its Transaction. To the extent the Customer is willing to pay the applicable Transmission Usage Charge for its requested Receipt Point-to-Delivery Point combinations(s), service will be available and will be provided to the extent physically and operationally feasible. The Customer must obtain or self-supply Ancillary Services pursuant to Part II.C of the Tariff.

1.2 Independent Transmission Provider Responsibilities: The Independent Transmission Provider shall plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide all Customers with Network Access Service over the Independent Transmission Provider's Transmission System. The Independent Transmission Provider shall endeavor to have constructed and placed into service sufficient transmission capability to deliver all Network Access Service Customers' Resources to serve Load. The Independent Transmission Provider will offer a mechanism for participants to identify long-term planning and expansion needs and to propose solutions (transmission, generation, or demand-side).

1.3 Service at Points without Concurrent Congestion Revenue Rights: Once a Customer agrees to pay the applicable Access Charge, it may use the Independent Transmission Provider's Transmission System to deliver Energy to its Network Loads from Resources when the Customer does not have Congestion Revenue Rights between the requested Receipt and Delivery Points. Such Energy shall be transmitted subject to the Customer paying the applicable Transmission Usage Charge. A Customer may revise or add Receipt Points or Delivery Points without an additional Access Charge.

2. Initiating Service

2.1 Condition Precedent for Receiving Service: A request for Network Access Service may be performed under an umbrella Service Agreement pursuant to Part VII of the Tariff. A request for Network Access Service must contain a written Application to: [the Independent Transmission Provider Name and Address], submitted at least sixty (60) days in advance of the calendar month in which service is to commence. The Independent Transmission Provider will consider requests for such service on shorter notice when feasible. Requests for Network Access Service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section B.2.8.

2.2 Application Procedures: A Customer requesting Network Access Service must submit an Application, with a deposit approximating the charge for one month of service, to the Independent Transmission Provider as far as possible in advance of the month in which service is to commence. Applications should be submitted by entering the information listed below on the Independent Transmission Provider's OASIS, which will provide a time-stamped record for the Application.

2.2.1 Applications That Do Not Require the Integration of Resources and Load: A Completed Application shall provide all of the information included in 18 CFR 2.20 including, but not limited to, the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service meets, or will be upon commencement of service, will meet the eligibility requirement under Part I of this Tariff;

(iii) The location of the specific Receipt Points and Delivery Points and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and Energy and the location of the Load ultimately served by the capacity and Energy transmitted. The Independent Transmission Provider shall treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to transmission information sharing agreements. The Independent Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and Energy to be delivered; an estimate of the capacity and Energy expected to be delivered to the Receiving Party; and the transmission transfer capability requested for each Receipt Point and Delivery Point on the Independent Transmission Provider's Transmission System; Customers may combine their requests for service in order to satisfy the minimum transmission capability requirement; and

(vi) Service Commencement Date and the term of the requested Network Access Service: The minimum term for Network Access Service is one hour.

2.2.2 Applications That Require the Integration of Resources and Load: A Completed Application shall provide all of the information included in 18 CFR 2.20 including, but not limited to, the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service meets, or upon commencement of service will meet, the eligibility requirement under Part I of this Tariff;

(iii) A description of the Load at each Delivery Point. This description must separately identify and provide the Customer's best estimate of the total Loads to be served at each transmission voltage level, and the Loads to be served from each Independent Transmission Provider substation at the same transmission voltage level. The description must include a ten (10) year forecast of service for summer and winter Load and Resource requirements beginning with the first year after the service is scheduled to commence and extending for the duration of the service request;

(iv) The amount and location of any demand responsive Loads included in the Network Load. This shall include the summer and winter capacity requirements for each demand responsive Load, that portion of the Load subject to demand response, the conditions under which a response can be implemented and any limitations on the amount and frequency of demand response. Customer should identify the amount of demand responsive Load (if any) included in the ten (10) year Load forecast provided in response to (iii) above.

(v) A description of Network Resources (current and term of request projection), which shall include, for each Network Resource:

—Unit size and amount of capacity from that unit to be designated as Network Resource
—VAR capability (both leading and lagging) of all Generators
—Operating restrictions
—Any periods of restricted operations throughout the year
  —Maintenance schedules
  —Minimum loading level of unit
  —Normal operating level of unit
—Any must-run unit designations required for system reliability or contract reasons
—Approximate variable generating cost ($/MWh) for redispatch computations
—Arrangements governing sale and delivery of power to third parties from generating facilities located in the Independent Transmission Provider's Service Area, where only a portion of unit output is designated as a Network Resource
—Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and Delivery Point(s) to the Independent Transmission Provider's Transmission System;

(vi) A description of Customer's Transmission System, if applicable:

—Load flow and stability data, such as real and reactive parts of the Load, lines, transformers, reactive devices and Load type, including normal and Emergency ratings of all transmission equipment in a Load flow format compatible with that used by the Independent Transmission Provider
—Operating restrictions needed for reliability
—Operating guides employed by system operators
—Contractual restrictions or committed uses of the Customer's Transmission System, other than the Customer's Network Loads and Resources
—Location of Network Resources described in subsection (v) above
—Ten (10) year projection of system expansions or upgrades
—Transmission System maps that include any proposed expansions or upgrades; and

(vii) Service Commencement Date and the term of the requested Network Access Service: The minimum term for Network Access Service is one hour.

The Independent Transmission Provider shall acknowledge the Completed Application within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Customer. If an Application fails to meet the requirements of this section, the Independent Transmission Provider shall notify the Customer filing the Application requesting service or Congestion Revenue Rights within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Independent Transmission Provider shall attempt to remedy deficiencies in the Application through informal communications with the Customer. If such efforts are unsuccessful, the Independent Transmission Provider shall return the Application without prejudice to the Customer filing a new or revised Application that fully complies with the requirements of this section. The Customer will be assigned a new priority consistent with the date of the new or revised Application. The Independent Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

2.3 Technical Arrangements to be Completed Prior to Commencement of Service: Network Access Service shall not commence until the Independent Transmission Provider and the Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Independent Transmission Provider shall exercise reasonable efforts, in coordination with the Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

2.4 Customer Facilities: To the extent Customer owns transmission facilities, the provision of Network Access Service shall be conditioned upon the Customer's constructing, maintaining and operating the facilities on its side of each Delivery Point or interconnection necessary to reliably deliver capacity and Energy from the Independent Transmission Provider's Transmission System to the Customer. The Customer shall be solely responsible for constructing or installing all facilities on the Customer's side of each such Delivery Point or interconnection.

2.5 Filing of Service Agreement: The Independent Transmission Provider must file Service Agreements or related agreements with the Commission to the extent required by applicable Commission regulations.

2.6 Notice of Deficient Application: If an Application fails to meet the requirements of the Tariff, the Independent Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Independent Transmission Provider shall attempt to remedy minor deficiencies in the Application through informal communications with the Customer. If such efforts are unsuccessful, the Independent Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of the Tariff, the Customer shall be assigned a new priority consistent with the date of the new or revised Application.

2.7 Response to a Completed Application: Following receipt of a Completed Application for Network Access Service, the Independent Transmission Provider shall make a determination of physical feasibility as required in Section B.5.2. The Independent Transmission Provider shall notify the Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application, either (i) if it will be able to offer Network Access Service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section B.5.3. Responses by the Independent Transmission Provider must be made as soon as practicable to all Completed Applications and the timing of such responses must be made on a non-discriminatory basis.

2.8 Execution of Service Agreement: Whenever the Independent Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section B.2.5 will govern the execution of a Service Agreement. Failure of a Customer to execute and return the Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section B.2.9 within fifteen (15) days after it is tendered by the Independent Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of a Customer to file another Application after such withdrawal and termination.

2.9 Initiating Service in the Absence of an Executed Service Agreement: If the Independent Transmission Provider and the Customer requesting Network Access Service cannot agree on all the terms and conditions of the Service Agreement, the Independent Transmission Provider shall file with the Commission, within thirty (30) days after the date the Customer provides written notification directing the Independent Transmission Provider to file, an unexecuted Network Access Service Agreement containing terms and conditions deemed appropriate by the Independent Transmission Provider for such requested Transmission Service. The Independent Transmission Provider shall commence providing Transmission Service subject to the Customer agreeing to (i) compensate the Independent Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this Tariff including posting appropriate security deposits in accordance with the terms of Section B.2.2.

2.10 Scheduling of Network Access Service: Under Network Access Service, a Customer can schedule transmission service or procure Energy through the Day-Ahead and Real-Time Markets. The scheduling procedures for both options are contained in Part III of this Tariff.

3. Network Resources

To the extent a Customer desires the Independent Transmission Provider to integrate, economically dispatch, and regulate the Customer's Resources to serve the Customer's Load, the Customer must designate Resources as described below. All other Customers will identify Receipt Points and Delivery Points through the Day-Ahead and Real-Time Markets pursuant to Part III of this Tariff.

3.1 Designation of Network Resources: All Customers desiring the Independent Transmission Provider to integrate, economically dispatch, and regulate its Resources to serve its load must designate sufficient Network Resources to meets its Load on a non-interruptible basis. Network Resources shall include all generation owned, purchased or leased by the Customer designated to serve Network Load under the Tariff. Network Resources may not include Resources, or any portion thereof, that are committed for sale to non-designated third-party Load or otherwise cannot be called upon to meet the Customer's Network Load on a non-interruptible basis. Any owned or purchased Resources that were serving the Customer's Loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Customer terminates the designation of such Resources.

3.2 Designation of New Network Resources: The Customer may designate a new Resource by providing the Independent Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made by a request for modification of service pursuant to an Application under Section B.2.

3.3 Designation of Alternate Resources: The Customer has the right to obtain alternate Resources, whether through a bilateral contract or through the Independent Transmission Provider-Administered Markets. Alternate Resources enable the Customer to substitute one Resource for another, generally on a short-term basis. An alternate Resource does not have to be committed to the Customer on a firm basis as does a Network Resource.

3.4 Substitution of Resources and Congestion Revenue Rights: The Customer may replace one designated Resource with another. The Customer may request a reconfiguration of the Congestion Revenue Rights it holds for the current Resource and request Congestion Revenue Rights for the new Resource pursuant to B.6 of the Tariff.

3.5 Termination of Network Resources: The Customer may terminate the designation of all or part of a generating Resource as a Network Resource at any time, but must provide notification to the Independent Transmission Provider as soon as reasonably practicable.

3.6 Customer Dispatch Obligation: As a condition to receiving Network Access Service, the Customer agrees to dispatch its Network Resources as requested by the Independent Transmission Provider, consistent with Part II of this Tariff. To the extent practicable, the redispatch of Resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Customers.

3.7 Transmission Arrangements for Network Resources Not Physically Interconnected with the Independent Transmission Provider: The Customer shall be responsible for any arrangements necessary to deliver capacity and Energy from a Network Resource not physically interconnected with the Independent Transmission Provider's Transmission System. The Independent Transmission Provider will undertake reasonable efforts to assist the Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

3.8 Limitation on Designation of Network Resources: The Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating Resource as a Network Resource. Alternatively, the Customer may establish that execution of a contract is contingent upon the availability of transmission service under the Tariff.

3.9 Customer Owned Transmission Facilities: The Customer that owns existing facilities that are determined by the Order No. 888 seven factor test to be Transmission Facilities may be eligible to receive consideration either through a billing credit or some other mechanism.

4. Designation of Network Load

To the extent a Customer desires the Independent Transmission Provider to integrate, economically dispatch, and regulate the Customer's Resources to serve the Customer's Load, the Customer must designate Loads as described below.

4.1 Network Load: The Customer must designate the individual Network Loads on whose behalf the Independent Transmission Provider will provide Network Access Service. The Network Loads shall be specified in the Service Agreement and shall include actual deliveries at Interfaces.

4.2 New Network Loads Connected with the Independent Transmission Provider: The Customer shall provide the Independent Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Independent Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section B.5.12 and shall be charged to the Customer in accordance with Part VIII of this Tariff.

4.3 New Interconnection Points: To the extent the Customer desires to add a new Delivery Point or interconnection point between the Independent Transmission Provider's Transmission System and a Network Load, the Customer shall provide the Independent Transmission Provider with as much advance notice as reasonably practicable.

4.4 Changes in Service Requests: Under no circumstances shall the Customer's decision to cancel or delay a requested change in Network Access Service (*e.g.*, the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Customer of its obligation to pay the costs of transmission facilities constructed by the Independent Transmission Provider and charged to the Customer as reflected in the Service Agreement. However, the Independent Transmission Provider must treat any requested change in Network Access Service in a non-discriminatory manner.

4.5 Annual Load and Resource Information Updates: The Customer shall provide the Independent Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Access Service under the Tariff. The Customer also shall provide the Independent Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Customer's Network Load, Network Resources, Transmission System or other aspects of its facilities or operations affecting the Independent Transmission Provider's ability to provide reliable service.

5. Service Availability

5.1 General Conditions: The Independent Transmission Provider shall provide Network Access Service over, on or across its Transmission System to any Customer that has met the requirements of Section A.9.

5.2 Determination of Available Transfer Capability: A description of the Independent Transmission Provider's specific methodology for assessing Available Transfer Capability posted on the Independent Transmission Provider's OASIS is contained in Attachment A of the Tariff. In the event sufficient transmission capability may not exist to accommodate a Congestion Revenue Rights request, the Independent Transmission Provider shall respond by performing a System Impact Study.

5.3 Notice of Need for System Impact Study: After receiving a request for Congestion Revenue Rights or for the reconfiguration of Congestion Revenue Rights, the Independent Transmission Provider shall conduct, to the extent necessary, a System Impact Study. A description of the Independent Transmission Provider's methodology for completing a System Impact Study is provided in Attachment B. The Independent Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Customer shall agree to reimburse the Independent Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Customer shall execute the System Impact Study Agreement and return it to the Independent Transmission Provider within fifteen (15) days. If the Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

5.4 System Impact Study Agreement and Cost Reimbursement

(i) The System Impact Study Agreement must clearly specify the Independent Transmission Provider's estimate of the actual cost and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Independent Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Customer will not be assessed a charge for such existing studies; however, the Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Customer's request for service on the Transmission System.

(ii) If in response to multiple Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Independent Transmission Provider to accommodate the service requests, the costs of that study shall be prorated among the Customers.

5.5 System Impact Study Procedures: Upon receipt of an executed System Impact Study, the Independent Transmission Provider shall use due diligence to complete the required System Impact Study within sixty (60) days. The System Impact Study shall identify any system constraints and dispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Independent Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Customer. The Independent Transmission Provider shall notify the Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service, all or part of a request for Congestion Revenue Rights reconfiguration, or if no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

5.6 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Customer's service request, Congestion Revenue Rights Request, or Congestion Revenue Rights Reconfiguration request, the Independent Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Customer a Facilities Study Agreement pursuant to which the Customer shall agree to reimburse the Independent Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Customer shall execute the Facilities Study Agreement and return it to the Independent Transmission Provider within fifteen (15) days. If the Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Independent Transmission Provider will use due diligence to complete the required Facilities Study within sixty (60) days. If the Independent Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Independent Transmission Provider shall notify the Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study shall include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Customer, (ii) the Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Customer shall provide the Independent Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Independent Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

5.7 Facilities Study Modifications: Any change in design arising from an inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Independent Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Customer pursuant to the provisions of Part II of the Tariff.

5.8 Due Diligence in Completing New Facilities: The Independent Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Independent Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Transmission Service or Congestion Revenue Rights if doing so would impair system reliability or otherwise impair or degrade existing service or Congestion Revenue Rights.

5.9 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System: If the Independent Transmission Provider determines that it cannot accommodate a request for service or Congestion Revenue Rights because of insufficient transmission capability on its Transmission System, the Independent Transmission Provider must use due diligence to expand or modify its Transmission System to provide the requested transmission service, provided the Customer agrees to compensate the Independent Transmission Provider for such costs pursuant to the terms of Section B.5.12. The Independent Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Independent Transmission Provider along with the Transmission Owner has the right to expand or modify.

5.10 Partial Interim Service: If the Independent Transmission Provider determines that it will not have adequate transmission capability to satisfy the full amount of a Completed Application for service, the Independent Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Network Access Service that can be accommodated without addition of any facilities and through redispatch. Partial service could be of an amount (MW) or duration. However, the Independent Transmission Provider shall not be obligated to provide the incremental amount of requested Transmission Service (or Congestion Revenue Rights) that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service. To the extent the Customer disagrees with the Independent Transmission Provider's determination of insufficient Available Transfer Capability (or redispatch capability), the Customer may request and the Independent Transmission Provider shall provide its workpapers and analysis.

5.11 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Customer shall have the option to expedite the process by requesting the Independent Transmission Provider to tender at one time, together with the results of required studies, an ''Expedited Service Agreement'' pursuant to which the Customer would agree to compensate the Independent Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Independent Transmission Provider agrees to provide the Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Customer must agree in writing to compensate the Independent Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

5.12 Compensation for New Facilities: Whenever a System Impact Study performed by the Independent Transmission Provider in connection with the provision of Network Access Service identifies the need for new facilities, the Customer shall be responsible for such costs to the extent consistent with Commission policy.

6. Procedures if The Independent Transmission Provider is Unable to Complete New Transmission Facilities for Transmission Service

6.1 Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Independent Transmission Provider shall promptly notify the Customer. In such circumstances, the Independent Transmission Provider shall within thirty (30) days of notifying the Customer of such delays, convene a technical meeting with the Customer to evaluate the alternatives available to the Customer. The Independent Transmission Provider also shall make available to the Customer studies and work papers related to the delay, including all information that is in the possession of the Independent Transmission Provider that is reasonably needed by the Customer to evaluate any alternatives.

6.2 Alternatives to the Original Facility Additions: When the review process of Section B.5.5 determines that one or more alternatives exist to the originally planned construction project, the Independent Transmission Provider shall present such alternatives for consideration by the Customer. If, upon review of any alternatives, the Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Independent Transmission Provider to submit a revised Service Agreement for Network Access Service and a request for associated Congestion Revenue Rights. If the alternative approach solely involves Network Access Service and the Customer is willing to pay any applicable Congestion Charges, the Independent Transmission Provider shall promptly tender a Service Agreement for Network Access Service providing for the service. In the event the Independent Transmission Provider concludes that no reasonable alternative exists and the Customer disagrees, the Customer may seek relief under the dispute resolution procedures pursuant to Section A.10 or it may refer the dispute to the Commission for resolution.

6.3 Refund Obligation for Unfinished Facility Additions: If the Independent Transmission Provider and the Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Transmission Service shall terminate and any deposit made by the Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Customer shall be responsible for all prudently incurred costs by the Independent Transmission Provider through the time construction was suspended.

7. Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

Part VI of this Tariff details Transmission Planning and Expansion.

8. Network Access Service Customer Responsibilities

8.1 Conditions Required of Customers: Network Access Service shall be provided by the Independent Transmission Provider only if the following conditions are satisfied by the Customer:

(i) The Customer has pending a Completed Application for service;

(ii) The Customer has met the creditworthiness and eligibility criteria set forth in Sections A.8 and A.9;

(iii) The Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Independent Transmission Provider prior to the time service under Part II of the Tariff commences;

(iv) The Customer has agreed to pay for any facilities constructed and chargeable to such Customer under Part II of the Tariff, whether or not the Customer takes service for the full term of its reservation; and

(v) The Customer has executed a Network Access Service Agreement or has agreed to receive service pursuant to Section B.2.9.

8.2 Customer Responsibility for Third-Party Arrangements: Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Customer requesting service. The Customer shall provide, unless waived by the Independent Transmission Provider, notification to the Independent Transmission Provider identifying such systems and authorizing them to schedule the capacity and Energy to be transmitted by the Independent Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Independent Transmission Provider will undertake reasonable efforts to assist the Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

9. Load Shedding and Curtailments

9.1 Procedures: Prior to the Service Commencement Date, the Independent Transmission Provider and the Customer shall establish Load Shedding and Curtailment procedures in accordance with this Tariff with the objective of responding to contingencies on the Transmission System. The Parties shall implement such programs during any period when the Independent Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. [The Independent Transmission Provider shall notify all affected Customers and other market participants (*e.g.,* suppliers) in a timely manner of any scheduled Curtailment.]

9.2 Transmission Constraints: During any period when the Independent Transmission Provider determines that a transmission constraint exists on the Transmission System that cannot be handled through the LMP Congestion Management System, and such constraint may impair the reliability of the Independent Transmission Provider's system, the Independent Transmission Provider shall take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Independent Transmission Provider's system. To the extent the Independent Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Independent Transmission Provider shall initiate procedures to redispatch resources on the Independent Transmission Provider's Transmission System on a least-cost basis without regard to the ownership of such resources.

9.3 Curtailments of Scheduled Deliveries: If a transmission constraint on the Independent Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Independent Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Independent Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. To the extent operationally feasible, the Independent Transmission Provider shall curtail transactions in the following order. Parties who do not have Congestion Revenue Rights in adequate amounts for their Receipt Point-Delivery Point combinations, shall be curtailed first. All other transactions that have a material impact on the transmission constraint will be curtailed on a pro rata basis. [The

Independent Transmission Provider must develop procedures addressing non-discriminatory Curtailment of parallel flows involving more than one transmission system.]

9.4 Load Shedding: To the extent that a system Contingency exists on the Independent Transmission Provider's Transmission System and the Independent Transmission Provider determines that it is necessary for the Independent Transmission Provider and the Customer to shed Load, the Customers shall be directed by the Independent Transmission Provider to shed Load on a non-discriminatory basis to alleviate the Emergency/reliability contingencies.

(i) The Independent Transmission Provider will act first, whenever feasible, to direct Customers who have not met their assigned share of Resource Adequacy Requirements, pursuant to Section I of this Tariff, to shed load, before requiring other Customers to shed load, up to the amount of the lesser of: (1) The Resource deficiency; or (2) the Customers' Day-Ahead Energy market schedules. Failure to comply with the Independent Transmission Provider's direction to shed load shall subject Customers to the penalty provisions of Section I.6.3.

9.5 System Reliability: Notwithstanding any other provisions of this Tariff, the Independent Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Access Service without liability on the Independent Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Access Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Independent Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Independent Transmission Provider's Transmission System, the Independent Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Access Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Independent Transmission Provider will give the Customer as much advance notice as is practicable in the event of such Curtailment. [The Independent Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Customer fails to respond to established Load Shedding and Curtailment procedures. The Independent Transmission Provider can assess a penalty for failure to curtail after a reasonable period of time.]

10. Rates and Charges

For any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

10.1 Monthly Access Charge: The Customer that is a Load-Serving Entity shall pay a monthly Access Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Independent Transmission Provider's Annual Transmission Revenue Requirement specified in Part VIII. The Access Charge applies only to deliveries to load on the Independent Transmission Provider's System. The Access Charge does not apply to any deliveries to hubs, wheel throughs, or Exports to neighboring transmission systems.

10.2 Determination of Customer's Monthly Network Load: The Customer's monthly Load is its hourly Load coincident with the Independent Transmission Provider's Monthly Transmission System Peak.

10.3 Transmission Usage Charges: The Customer shall pay a Transmission Usage Charge for the quantity in MWh scheduled for Transmission Service. The Transmission Usage Charge will recover applicable Congestion Charges and losses, consistent with Sections F.3.3 and G.4.3, as applicable.

11. Operating Arrangements

11.1 Operation Under the Network Operating Agreement: The Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

11.2 Network Operating Agreement: The terms and conditions under which the Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part II of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Customer within the Independent Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Independent Transmission Provider and the Customer (including, but not limited to, heat rates and operational characteristics of Resources, generation schedules for units outside the Independent Transmission Provider's Transmission System, interchange schedules, unit outputs for dispatch, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted Loads and Resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Customer shall either (i) self-supply, contract for, or purchase from the Independent Transmission Provider all necessary Ancillary Services consistent with Good Utility Practice, which satisfies NERC and the [applicable regional reliability council] requirements. The Independent Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included under Part VII.

11.3 Network Operating Committee: A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

12. Reservation Priority for Existing Firm Service Customers

12.1 Right of First Refusal: Prior to the effectiveness of a full auction mechanism for all Congestion Revenue Rights, Congestion Revenue Rights will be allocated to Customers with long-term firm contracts under which the Customer continues to pay the Access Charge. To ensure that these Customers are able to maintain that right until the time that Congestion Revenue Rights are auctioned, existing firm service Customers (wholesale requirements and transmission-only, with a contract term of one-year or more), have the right to continue to take Network Access Service and agreeing to pay the Access Charge when the existing contract expires, rolls over or is renewed. If at the end of the contract term, the Independent Transmission Provider's Transmission System cannot accommodate all of the requests for Congestion Revenue Rights, the existing firm service Customer must agree to accept a contract term at least equal to a competing request by any new Customer and to pay the Access Charge, as approved by the Commission, for such service. This priority for existing firm service Customers is an ongoing right that may be exercised at the end of all firm contract terms of one-year or longer. This section will remain in effect until the Independent Transmission Provider places into effect an auction mechanism for allocating all Congestion Revenue Rights.

12.2 Notice of Rollover: Consistent with requests for new service described in Section B.2.1 of the Tariff, a Customer must submit its request to exercise rollover rights no later than sixty (60) days prior to the date the current service agreement expires.

C. Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Service Areas affected by the transmission service. The Independent Transmission Provider is required to provide, and the Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch Service, (ii) Reactive Supply and Voltage Control from Generation Sources Service; and (iii) Energy Imbalance Service.

The Independent Transmission Provider is required to offer to provide the following Ancillary Services only to the Customer serving Load within the Independent Transmission Provider's Service Area (i) Regulation and Frequency Response Service, (ii) Operating Reserve-Spinning Reserve Service, and (iii) Operating Reserve-Supplement Reserve Service. The Customer serving Load within the Independent

Transmission Provider's Service Area is required to acquire these Ancillary Services, whether from the Independent Transmission Provider or a market operated by the Independent Transmission Provider, from a third party, or by self-supply. The Customer may not decline the Independent Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Customer must list in its Application which Ancillary Services it will purchase from the Independent Transmission Provider.

The Independent Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Customer's agent to secure these Ancillary Services from others or by operating a market for the services. The Customer may elect to (i) have the Independent Transmission Provider act as its agent and procure Regulation and Frequence Response Service and Operating Reserves through the markets in Part III or (ii) secure Regulation and Frequency Response Service and Operating Reserves from a third party or by self-supply when technically feasible.

1. Scheduling, System Control and Dispatch Service

This service is required to schedule the purchase, sale and movement of power through, out of, within, or into the Independent Transmission Provider's Service Area. This service can be provided only by the Independent Transmission Provider. The Customer must purchase this service from the Independent Transmission Provider. The charges for Scheduling, System Control and Dispatch Service are set forth below.

1.1 Billing Units and Calculation of Rates: The Independent Transmission Provider shall charge each Customer based on the product of:

(i) the Scheduling, System Control and Dispatch Service charge rates; and

(ii) the Customer's applicable billing units for the month, as follows: [Independent Transmission Provider to propose rate methodology.]

2. Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on the Transmission System within acceptable limits, generation facilities under the control of the Independent Transmission Provider are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service (''Voltage Support Service'') must be provided for each Transaction on the Transmission System. The amount of Voltage Support Service that must be supplied with respect to the Customer's Transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Independent Transmission Provider. Voltage Support Service is to be provided directly by the Independent Transmission Provider. The methodologies that the Independent Transmission Provider will use to obtain Voltage Support Service and the associated charges for such service are set forth below. [To be provided by the Independent Transmission Provider.]

3. Regulation Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of Resources (generation and interchange) with Load in order to maintain scheduled Interconnection frequency. Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in Load. The obligation to maintain this balance between Resources and Load lies with the Independent Transmission Provider. Each Load-Serving Entity must either purchase this service through the Independent Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

The Independent Transmission Provider shall establish Day-Ahead and Real-Time Markets for Regulation to procure through the Day-Ahead and Real-Time Markets that portion of Regulation Requirement not met through Self-Supply. The full Regulation Requirement shall be cleared through the Day-Ahead Market. The Real-Time Market will provide an alternate supply for Regulation Service during the Operating Day where (i) Suppliers scheduled in the Day-Ahead Market are inadequate; (ii) a scheduled Supplier is unable to provide Regulation Service (*e.g.,* the Generator tripped); (iii) the demand for Regulation Service increases beyond the scheduled supply; or (iv) other adjustments to the supply or demand of Regulation can be efficiently made. The Independent Transmission Provider shall select Suppliers in the Real-Time Market, during the Operating Day, to provide Regulation Service for each hour in which an insufficient supply of Regulation Service exists or when a supplier Bidding in the Real-Time market can provide Regulation service at a lower cost than a supplier that has been scheduled in the Day-Ahead Market.

The Market Rules for the Day-Ahead Market for Regulation are set forth in Section F.4. The Market Rules for the Real-Time Market for Regulation are set forth in Section G.4.

4. Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of Energy to a Load located within the Independent Transmission Provider's Service Area. This service will be provided through the Real-Time Energy Market operated by the Independent Transmission Provider. The procedures that will be used are described in Part III below.

5. Operating Reserves

The Independent Transmission Provider shall provide procedures to establish adequate Operating Reserves that comply with applicable Reliability Rules. Operating Reserves are classified as follows:

(i) Spinning Reserve: Operating Reserves provided by Resources (Generation and Demand) located within the Independent Transmission Provider Service Area that are already synchronized to the Power System and can respond to instructions to change output level within ten (10) minutes;

(ii) Supplemental Reserve: Operating Reserves provided by Resources (Generation and Demand) that can respond to instructions to change output or consumption level within ten (10) minutes or some other specified time period.

Operating Reserves can be ranked in terms of quality. Spinning Reserves are a higher quality reserve product than Supplemental Reserves. Supplemental Reserves that can respond to instructions on a shorter time frame (*e.g.,* 10 minutes) than other Supplemental Reserves (*e.g.,* 30-minutes) also have a higher quality ranking. The Independent Transmission Provider must substitute higher quality operating reserves for lower quality operating reserves when it is economical to do so.

The Independent Transmission Provider shall establish Day-Ahead and Real-Time Markets for Operating Reserves. The full requirement for Operating Reserves shall be cleared through the Day-Ahead Market. The Real-Time Markets will provide an alternate supply for Operating Reserves during the Operating Day where (i) Suppliers scheduled in the Day-Ahead Market are inadequate; (ii) a scheduled Supplier is unable to provide Operating Reserves (*e.g.,* the Generator tripped); (iii) the demand for Operating Reserves increases beyond the scheduled supply; or (iv) other adjustments to the supply or demand of operating reserves can be efficiently made. The Independent Transmission Provider shall select Suppliers in the Real-Time Market, during the Operating Day, to provide Operating Reserves for each hour in which an insufficient supply of Operating Reserves exists or when a supplier Bidding in the Real-Time market can provide Operating Reserves at lower costs than a supplier than has been scheduled in the Day-Ahead Market.

The Market Rules for the Day-Ahead Markets for Operating Reserves are set forth in Sections F.5 and F.6. The Market Rules for the Real-Time Markets for Operating Reserves are set forth in Sections G.6 and G.7.

D. Congestion Revenue Rights

Preamble

A Congestion Revenue Right is a right held by a Customer which provides the Customer with a hedge against uncertain future Congestion Charges by paying the holder of the right a stream of specified congestion revenues. This section details the specific types of Congestion Revenue Rights, the specific properties of Congestion Revenue Rights, and how Congestion Revenue Rights are acquired.

1. Types of Congestion Revenue Rights

The Independent Transmission Provider shall make available, through the processes identified in Section D.3, Receipt Point-to-Delivery Point Congestion Revenue Right Obligation as described below. In addition, upon request of Market Participants, the Independent Transmission Provider shall make available Receipt Point-to-Delivery

Congestion Revenue Right Options as well as Flowgate Congestion Revenue Rights, as soon as technically feasible.

1.1 Receipt Point-to-Delivery Point Congestion Revenue Rights: A Receipt Point-to-Delivery Point right is specified by a Receipt Point and a Delivery Point, the total MW that are to be injected at the Receipt Point and withdrawn at the Delivery Point, whether the right is an Obligation or an Option, and the period of time for which the right is in effect.

1.1.1 Obligation Rights: Receipt Point-to-Delivery Point Congestion Revenue Right Obligations confer to the holder (i) the right to collect revenues equal to the applicable Marginal Congestion Component of the hourly Transmission Usage Charge from the Receipt Point to the Delivery Point when the Marginal Congestion Component is positive, and (ii) the obligation to pay an amount to the Independent Transmission Provider equal to the absolute value of the applicable Marginal Congestion Component of the hourly Transmission Usage Charge from the Receipt Point to the Delivery Point when the Marginal Congestion Component is negative.

1.1.2 Option Rights: Receipt Point-to-Delivery Point Transmission Option Rights confer to the holder the right to collect revenues equal to the applicable Congestion Charge component of the hourly Transmission Usage Charge from the Receipt Point to the Delivery Point when the Marginal Congestion Component is positive, but do not obligate the holder to pay the absolute value of the applicable Marginal Congestion Component of the hourly Transmission Usage Charge when the Marginal Congestion Component is negative.

1.1.3 Types of Receipt Points and Delivery Points: The Receipt Points and Delivery Points specified in the Receipt Point-to Delivery Point Congestion Revenue Right can be a Generator bus, a load bus, an Interface between the Independent Transmission Provider's Service Area and an adjacent Service Area, or a pre-defined set of buses (which can be either Zones or Hubs).

1.2 Flowgate Congestion Revenue Rights

1.2.1 Definition of Flowgates and Flowgate Rights: A Flowgate is a transmission facility (such as a transmission line or a transformer or some other component of the electrical network) or group of facilities (e.g., an Interface) that constrains the power transfer capability of the network. A Flowgate Right is specified by a portion of the total MW capability over a particular transmission Flowgate in a specified direction. Flowgate Rights entitle the holder to collect Congestion revenues (as determined consistent with Section F.3.5.2) associated with the specified MW flow over the identified Flowgate in the specified direction in the Day-Ahead Market.

2. Term of Congestion Revenue Rights

During the first two years of operation of the Independent Transmission Provider's Bid-based markets, the Independent Transmission Provider shall offer Congestion Revenue Rights for sale through the auction procedures in Section D.7 with terms of 1 year, 6 months, and 1 month. Beginning in the third year of operation of the Independent Transmission Provider's Bid-based markets, the Independent Transmission Provider shall offer Congestion Revenue Rights with terms of 10 years, 5 years, 1 year, 6 months, and 1 month. Upon request of Market Participants, the Independent Transmission Provider may also offer Congestion Revenue Rights for other terms. These term limitations will not apply to Congestion Revenue Rights acquired through the initial allocation procedures for implementation of Standard Market Design.

3. Scheduling Priority for Holders of Congestion Revenue Rights in the Event of Curtailment

In any hour in which the Independent Transmission Provider is unable to accept all requested schedules for Transmission Service at the applicable Day-Ahead Transmission Usage Charges, holders of Receipt Point-to-Delivery Point Congestion Revenue Rights shall have scheduling priority from their designated Receipt Points to their designated Delivery Points over Customers that do not hold Congestion Revenue Rights. [The Independent Transmission Provider shall develop a method for determining how to implement such priority, which shall be inserted here.]

4. Existing Transmission Contracts

Transmission Service pursuant to each Existing Transmission Contract shall be provided by the Independent Transmission Provider for the account of the Existing Transmission Contract Transmission Owner, acting as agent for the Existing Transmission Contract Customer. The Independent Transmission Provider shall assess to the Existing Transmission Contract Transmission Owner all charges and payments associated with providing Transmission Service pursuant to this Tariff. Consistent with the provisions of this Tariff, the Transmission Owner may acquire Congestion Revenue Rights to hedge against the Congestion costs associated with Transmission Service provided pursuant to its Existing Transmission Contracts.

4.1 Conversion of Existing Transmission Contracts: Upon the mutual agreement of the parties to any Existing Transmission Contract, the Existing Transmission Contract Customer may terminate its Existing Transmission Contract in exchange for receiving Congestion Revenue Rights previously held by the Transmission Owner to support the Existing Transmission Contract described in Section D.3 with the same MW level of service and with the same Receipt Points and Delivery Points and termination date as specified in the Existing Transmission Contract.

5. Allocation of Congestion Revenue Rights

5.1 Allocation of Congestion Revenue Rights: The aggregate set of Congestion Revenue Rights allocated to Customers shall not exceed an amount that is Simultaneously Feasible, as determined pursuant to Section D.5.8, in light of the total transmission capability in the Independent Transmission Provider's Service Area under normal operating conditions. In determining whether a set of Congestion Revenue Rights is Simultaneously Feasible, the Total Transfer Capability of the transmission system shall not be reduced by the transfer capability needed to support existing Customers.

5.2 Requirement to Conduct Periodic Auctions for Congestion Revenue Rights. The Independent Transmission Provider shall conduct periodic auctions over its OASIS, consistent with Section D.5, that will provide Bid-based markets to buy and sell Congestion Revenue Rights for a variety of terms. Each auction shall provide for the opportunity to buy and sell Receipt Point-to-Delivery Point Congestion Revenue Right Obligations, as described in Section D.1. Upon the request of Market Participants, auctions shall provide for the opportunity to buy and sell Receipt Point-to-Delivery Point Transmission Option Rights and Flowgate Rights, as soon as it is technically feasible to do so.

The periodic Congestion Revenue Rights auctions will also provide for the sale of Congestion Revenue Rights associated with transmission capability that becomes available after the initial allocation of Congestion Revenue Rights, for example, due to the expiration of initially allocated Congestion Revenue Rights.

[The Independent Transmission Provider shall file procedures which may have either an allocation of Congestion Revenue Rights or an allocation of auction revenues from the sale of Congestion Revenue Rights.]

6. Resale of Congestion Revenue Rights

All holders of Congestion Revenue Rights may resell their Congestion Revenue Rights outside the auction held pursuant to Section D.3.2. However, the Independent Transmission Provider shall make all Settlements with Primary Holders. Buyers of resold Congestion Revenue Rights that elect to become Primary Holders must meet the eligibility criteria in Section A.9 of this Tariff.

Sellers and potential buyers shall communicate all offers to sell and buy Congestion Revenue Rights, solely over the Independent Transmission Provider's OASIS.

7. Auctions for Congestion Revenue Rights

The Independent Transmission Provider shall conduct periodic auctions to allow Market Participants to buy and sell Congestion Revenue Rights.

7.1 General Description of the Auction Process: In each auction, Market Participants will have the opportunity to submit Bids to buy and sell Congestion Revenue Rights for a specified term. In each auction, the Independent Transmission Provider shall consider all Bids and shall select a combination of Bids that (i) is Simultaneously Feasible in light of the Transmission Capability that is expected to be available over the term of the transactions and (ii) maximizes the combined net economic value (as expressed in the Bids) of the selected Bids. In order to maximize the net economic value of the selected Bids, the auction shall allow for the reconfiguration of Congestion Revenue Rights. That is, the Congestion Revenue Rights that are offered for sale may be converted into Congestion Revenue Rights of a different type or with different Receipt and Delivery Points.

7.2 Frequency of Congestion Revenue Rights Auction: The Independent

Transmission Provider shall conduct an Auction for Congestion Revenue Rights no less frequently that once in every calendar month.

7.3 Responsibilities of the Independent Transmission Provider Prior to Each Auction

7.3.1 Establish Auction Rules: The Independent Transmission Provider shall use the auction rules and procedures consistent with this Tariff. [Independent Transmission Provider may file to add additional auction rules.]

7.3.2 Evaluate Creditworthiness: The Independent Transmission Provider shall evaluate each Bidder's ability to pay for Congestion Revenue Rights, consistent with the creditworthiness provisions of Section A.8. As a result of this evaluation, the Independent Transmission Provider shall state a limit before the auction on the value of the Congestion Revenue Rights that the entity may be awarded in the auction, and collect signed statements from each entity Bidding into the auction committing that entity to pay for any Congestion Revenue Rights that it is awarded in the auction. Bidders will not be permitted to submit Bids that exceed this allowable limit.

7.3.3 Information to be Made Available to Bidders: To aid Market Participants in their participation in the auction, the Independent Transmission Provider shall make the following information available before each auction:

(i) for each Generator bus, Load bus, external bus and Load Zone for each of the previous 5 years, if available, (a) the average Marginal Congestion Component of the LMP, relative to the Reference Bus, and (b) the average Marginal Losses Component of the LMP, relative to the Reference Bus;

(ii) for each of the previous two 6-month periods, (a) historical flow histograms for each of the closed Interfaces, and (b) historically, the number of hours that the most limiting facilities were physically constrained;

(iii)(a) Power Flow data to be used as the starting point for the auction, including all assumptions, (b) assumptions made by the Independent Transmission Provider relating to transmission maintenance outage schedules, (c) all limits associated with transmission facilities, contingencies, thermal, voltage and stability to be monitored as Constraints in the Optimum Power Flow determination, and (d) the Independent Transmission Provider summer and winter operating study results (non-simultaneous Interface Transfer Capabilities).

7.3.4 Other Responsibilities: The Independent Transmission Provider will establish an auditable information system to facilitate analysis and acceptance or rejection of Bids, to provide a record of all Bids, and to provide all necessary assistance in the resolution of disputes that arise from questions regarding the acceptance, rejection, award and recording of Bids. The Independent Transmission Provider will establish a system to communicate auction-related information to all auction participants.

The Independent Transmission Provider will receive Bids to buy Congestion Revenue Rights from any entity that meets the eligibility criteria established in this Tariff and will implement the auction Bidding rules previously established by the Independent Transmission Provider.

The Independent Transmission Provider will properly utilize an Optimal Power Flow program to determine the set of winning Bids for each auction and calculate the Market Clearing Price of all Congestion Revenue Rights at the conclusion of the auction, in the manner described in this Tariff.

7.4 Responsibilities of each Buying Bidder

7.4.1 Creditworthiness Information: Each Bidder must submit such information to the Independent Transmission Provider regarding the Bidder's creditworthiness as the Independent Transmission Provider may require consistent with Section A.8, along with a statement signed by the Bidder, representing that the Bidder is financially able and willing to pay for the Congestion Revenue Rights for which it is Bidding. The aggregate value of the Bids submitted by any Bidder into the auction shall not exceed that Bidder's ability to pay or the maximum value of Bids that Bidder is permitted to place, as determined by the Independent Transmission Provider (based on an analysis of that Bidder's creditworthiness).

Each Bidder must pay the Market Clearing Price for each Congestion Revenue Right it is awarded in the auction.

7.5 Responsibilities of Each Selling Bidder

7.5.1 Bids to Sell Congestion Revenue Rights: Each Market Participant desiring to sell Congestion Revenue Rights Shall include the following information in its Bid:

(i) The type of Congestion Revenue Right (i.e., Receipt Point-to-Delivery Point Congestion Revenue Right Obligation, Receipt Point-to-Delivery Point Transmission Option Right, or Flowgate Congestion Revenue Right).

(ii) The Receipt and Delivery Points, if a Receipt Point-to-Delivery Point Right is offered.

(iii) The location and direction of the Flowgate, if a Flowgate Right is offered.

(iv) The MWs

(v) The minimum acceptable price, if any.

(vi) The term.

Each seller that offers Congestion Revenue Rights for sale that it has been awarded must provide verification of the award to the Independent Transmission Provider when the Bid is submitted.

7.6 Selection of Winning Bids and Determination of the Market Clearing Price: The Independent Transmission Provider shall determine the winning set of Bids in each auction as the set of Bids that maximizes the value (as expressed in the Bids) of the Congestion Revenue Rights, subject to the constraint that the selected set of Bids must be simultaneously feasible consistent with Section D.5.8.

The Market Clearing Price for each Congestion Revenue Right shall equal the change in the net economic value of all other Bidders that would result from awarding an additional 1 MW of that Congestion Revenue Right to a Market Participant.

7.7 Auction Settlement: The Independent Transmission Provider will determine prices in the auction for feasible Congestion Revenue Rights, consistent with Section 6.6. Each Bidder awarded Congestion Revenue Rights in the auction shall pay the applicable Market Clearing Price for those Congestion Revenue Rights that is awarded in the auction. Similarly, each Congestion Revenue Right holder selling Congestion Revenue Rights through the Auction shall be paid the applicable Market Clearing Price for those Congestion Revenue Rights that are sold in the auction.

7.8 Simultaneous Feasibility: The set of winning Bids selected in each auction shall be simultaneously feasible based on the Transfer Capability available for purchase within the Independent Transmission Provider's Service Area under normal operating conditions. A set of Bids shall be deemed simultaneously feasible if both of the following Conditions, A and B, are met:

Condition A: Each set of injections and withdrawals associated with (i) winning, as well as outstanding previously-awarded, Receipt Point-to-Delivery Point Congestion Revenue Right Obligations along with (ii) any combination of winning, as well as previously awarded, Receipt Point-to-Delivery Point Congestion Revenue Right Option Rights, would not exceed any thermal, voltage, or stability limits within the Independent Transmission Provider's Service Area under normal operating conditions or for monitored contingencies.

Condition B: For each Flowgate in each direction, the power flow on the Flowgate in the specified direction resulting from the set of injections and withdrawals identified in Condition A, when added to the total Flowgate Rights awarded on the Flowgate in the specified direction, would not exceed the capability of the Flowgate available in the Auction.

The Power Flow simulations shall take into consideration the effects of parallel flows on the Transfer Capability of the Independent Transmission Provider's transmission system when determining which sets of injections and withdrawals are simultaneously feasible.

When performing the above Power Flows, injections for Receipt Point-to Delivery Point Congestion Revenue Rights that specify a Zone or a Hub as the injection location will be modeled as a set of injections at each bus in the injection Zone or Hub equal to the product of the number of Receipt Point-to-Delivery Point Congestion Revenue Rights and the percentage weights for each bus in the Zone or Hub.

When performing the above Power Flows, withdrawals for Receipt Point-to Delivery Point Congestion Revenue Rights that specify a Zone or Hub as the withdrawal location will be modeled as a set of withdrawals at each bus in the withdrawal Hub equal to the product of the number of Receipt Point-to Delivery Point Congestion Revenue Rights and the percentage weights for each bus in the Zone.

7.9 Responsibilities of the Independent Transmission Provider upon Completion of the Auction: The Independent Transmission Provider shall not reveal the Bid Prices submitted by any Bidder in the Auction until three months following the date of the auction, except as permitted by Section A.12. When these Bid Prices are posted, the names