UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination	)	
Through Open Access Transmission Service	)	Docket No. RM01-12-000
And Standard Electricity Market Design	)	

INITIAL COMMENTS OF
JOHN D. CHANDLEY AND WILLIAM W. HOGAN
ON THE STANDARD MARKET DESIGN NOPR
November 11, 2002

EXECUTIVE SUMMARY

Introduction

The principles of open access and non-discrimination require fundamental change in the rules and organization of the electricity system. Much of the old system depends to some degree on discrimination among transmission users and limitations on access to the electric grid and its essential services. The Commission's Standard Market Design (SMD) is needed to overcome this discrimination and open the grid to achieve an economically efficient electricity system. Equally important, the Commission's SMD initiative is needed because the market cannot solve the problem of market design.

In defining the core elements of its SMD, the Commission is fundamentally on the right track. The critical centerpiece of the design is a spot market for energy and ancillary services coordinated by an Independent Transmission Provider (ITP). This spot market would employ a bid-based, security-constrained, economic dispatch with locational marginal cost pricing (LMP).

Using a single transmission tariff, the framework accommodates both bilateral contracts and spot trading, while supporting utilities that wish to use their own resources to serve their own loads.

The SMD also responds to concerns about infrastructure development. The incentives from locational pricing provide a natural market stimulus to sustain generation and demand-side investments. In addition, the creation and award of financial transmission rights (called Congestion Revenue Rights or CRRs) provide further opportunities and incentives for market participants to undertake transmission expansion. Participant funding can then become a primary mechanism to support new transmission investments, while license plate rates would be used to recover the revenue requirements of the existing grid. Any needed investments that the market failed to pursue would have their costs assigned to beneficiaries or else rolled into license plate rates.

With the core SMD features in place, regions that have undergone restructuring and retail choice will have the necessary foundation. Other states could continue to operate much as they have in the past, with a mix of utility ownership of generation, long-term contracts and closed retail markets. The ITP's unbiased grid operations and open spot markets would support all of these options, while eliminating the system of closed and discriminatory access to the transmission grid. Claims that the NOPR would undermine traditional state utility regulation and the ability of state regulators to affect retail rates thus fundamentally misinterpret what the NOPR proposes and the Commission intends.

An important strategic feature of the SMD initiative is in describing a coherent vision for a stable and workable electricity system based on open, non-discriminatory access. Without an SMD, and at great expense, the country has gone through an extended period of experimentation with designs for electricity market institutions. There have been notable successes, as in the

Eastern ISOs, but also notable failures. The failures have brought the nation to a crossroads in electricity restructuring, with some urging the Commission to halt or turn back. Learning from these failures is essential, but turning back would be the wrong lesson, and standing still is not tenable.

The Commission must move forward with the core elements of SMD. The electricity system requires an ITP's visible but unbiased hand to coordinate the markets and assure reliability. Equally important, the present condition of the industry and the pervasive uncertainty this creates for investors require firm resolve to put the critical institutions in place at the earliest practical date. Moving forward will clarify the industry's emerging structure and make transparent the incentives for investment.

Only the Commission has the necessary scope of authority and responsibility to meet this challenge. Putting the critical institutions in place is the Commission's first priority. It is not sufficient by itself, but because it is necessary for a successful energy market, it should be done in essentially the same way, everywhere, and soon.

The Commission's SMD Contains Both Essential Features of a Workable Market Design and Enhanced Features that Would Improve Market Operations and Reliability.

There are many elements in the proposed SMD, but the core features center around the ITP's real-time spot markets using a bid-based, security-constrained, economic dispatch with locational prices. Associated real-time markets for ancillary services and the availability of Congestion Revenue Rights complement these features, while enhancing reliability, market flexibility and proper incentives. Open access to the dispatch and associated spot markets then support the ITP in providing open, non-discriminatory Network Access Service to all grid users. There are many details to consider, but the SMD gets most of them right.

Beyond these core features, the SMD identifies further enhancements that are possible in the day-ahead time frame, including day-ahead energy markets, simultaneously optimized ancillary service markets and reliability unit commitment processes. But these enhancements should not be the Commission's priority. The priority should be in putting the essential ITP institutions in place and ensuring that they operate the SMD's real-time markets with Network Access Service.

In extended discussions of the real-time and day-ahead markets, we comment on a select list of items that may benefit from further analysis. The intent is to distinguish between the core features that are essential to the design and should therefore be standardized and receive priority attention, and those that are of secondary importance or not necessary to standardize. On many secondary issues, we recommend against standardization now. We point out where somewhat different approaches would be acceptable and would not undermine the essential core features.

The Commission Proposes a Workable Framework for Market Power Mitigation by Recognizing the Need to Balance Mitigation with the Need for Scarcity Pricing.

Concerns about market power present a challenge for electricity markets that must be addressed to restore public confidence in market reforms. The Commission's analysis correctly highlights the two principal problems with current electricity markets. First, there is a present lack of sufficient demand-side response. Second, transmission constraints can create small local pockets where there is an effective monopoly.

The Commission's targeted mechanisms attempt to distinguish between high prices due to scarcity and high prices caused by an exercise of market power. Here, the use of bid caps, rather than price caps, is consistent with the core elements of SMD and avoids the problems of price caps. A price cap that applies to the outcome of the market process is difficult to implement and prone to creating inefficient outcomes and perverse incentives for investment. By contrast, a bid cap applied to those who could exercise market power targets the problem but does not carry with it the same difficulties as a price cap. Under the bid cap approach, sellers who have market power must offer their power with approved bids but the market price is determined through the usual spot market mechanism and applies to everyone. The Commission would have the ITP identify an appropriate bid cap for the sellers in load pockets and couple this with a "must offer" requirement. The basic principles are sound and consistent with the broader SMD framework.

We agree that a properly structured safety net bid cap to achieve a proxy for scarcity prices can be a transitional substitute for inadequate demand-side response. The safety net bid cap should be close to the price at which load would be prepared to voluntarily reduce if only the market institutions were in place to make this reduction possible. Seen as a proxy for the true value of demand, the $1000 per MWH number may well be too low. Part of the task for the Commission, therefore, will be to address the justification for any safety net bid caps below this level and to consider a transition process that gradually increases the safety net cap as demand-side participation in the market improves.

As the third part of the Commission's proposed market power mitigation plan, the resource adequacy requirement is problematic. It would be wise for the Commission to take care in implementing the other features of the market power mitigation plan without relying on the success of a long-term resource adequacy proposal to counteract any problems created by the market power mitigation rules.

The Commission is correct to be cautious about imposing automatic mitigation procedures (AMP), which can be become overly intrusive if not carefully designed and implemented. A concern with an AMP would come in the implementation, because the potentially intrusive and comprehensive nature of the AMP could significantly exacerbate the problem that the Commission has identified by tipping the balance too much in favor of mitigation to the point of precluding even an approximation of true scarcity pricing. We note steps that have been taken in New York to address these concerns.

In summary, the Commission has the right framework for market power mitigation and recognizes the need to balance with the requirements of scarcity pricing. The use of bid caps in the twin settings of local market power mitigation and a safety net designed as a proxy for demand-side response is consistent with the SMD core elements and the broad objectives of electricity restructuring. If these elements are handled well, it could obviate the need for the more problematic proposal for a resource adequacy requirement.

The Proposed Resource Adequacy Requirement Could Undermine the Expected Benefits of Workable Markets.

While the Commission's basic prescription for market design is fundamentally sound, the Commission is struggling to define an appropriate RAR that does not inadvertently undermine the SMD's core features and expected benefits. By now, the Commission is presumably aware of the more obvious drawbacks of its particular approach.

States with retail choice programs will point out that the proposal is problematic where consumers are allowed to switch from one LSE to another or move between regulated default suppliers and competitive LSEs on short notice. Other comments will likely note that the complex integrated resource planning functions required to implement the Commission's proposal constitute a substantial undertaking by institutions that do not yet exist (except possibly in the Northeastern ISOs). The NOPR's list of tasks that these new institutions must perform is daunting. In the end, all of the structures of integrated resource planning fashioned by the states in the 1980s would reappear, but with different institutions in charge.

A more telling observation is that when it comes to the enforcement mechanism, the Commission's proposal relies on the fundamental premise that short-run prices (including penalties) for uncontracted quantities and the risks of curtailment are what really matter. If that is true, then the Commission, RTOs, states and parties could dispense with all of the unneeded complexity of integrated resource planning and rely on the short-run price incentives and the natural desire of LSEs to avoid selective involuntary curtailments, to the extent these were feasible. The design task would then be to set the penalties for spot market usage to provide the right incentives for forward commitments that would, in turn, lead to adequate investment levels. To work as they should, the penalties would probably need to be higher than suggested in the NOPR, and instead defined by shortage costs and the willingness of loads to pay to avoid involuntary curtailment.

A logical and worthwhile outcome of the penalty approach would end up with the charge applying formally to all spot transactions. And the penalty should be essentially the same as would have been produced by allowing market-clearing spot prices on their own. The Commission proposal could logically evolve toward a system in which short-run prices would do more or less what the spot markets would do if prices were allowed to clear the markets at all times, including periods of shortages or near shortages.

Despite the Commission's (sometimes valid) criticisms of installed capacity (ICAP) requirements, all of the issues in ICAP would arise if the Commission attempted to "fix" its own proposal along the path of a forward resource obligation. In the final analysis, there is no escaping the fundamental choice between letting the spot markets clear at prices that reflect scarcity costs or confronting the many difficult issues in designing ICAP mechanisms. Because the choice cannot be avoided, the Commission should not tell the Northeast ISOs that they must replace ICAP while telling them that a market-clearing alternative is out of the question.

Given the SMD's strong support for easy long-term contracting to hedge energy requirements, the concern over spot price exposure seems misplaced. In addition to such contracts, those customers deemed to be too small to justify interval metering would face monthly average prices, not hourly spot market prices. Customers that are large enough to justify interval metering and billing systems could hedge themselves, particularly if these customers faced retail rates in which real-time spot prices were applied to marginal usage.

In summary, the Commission's proposals for RAR tackle a problem that may not exist, and may not have a solution in any event that is consistent with the basics of the SMD. The feasibility of targeted curtailment is not obvious, and the use of penalties for undercontracting appears inferior to the simpler process of allowing prices to clear the energy and reserve markets. Long-term contracting should be made easy, but not mandatory. The emphasis should be on financial hedging contracts, not explicit capacity requirements. And a focus on developing demand-side participation would target the real source of concern. Implementing the proposed RAR and thereby replacing the old utility-run integrated resource investment programs with the ITP-run integrated resource investment programs would ratify the criticisms of open access and non-discrimination as not worth the effort.

The alternative to allowing prices to clear the markets is not easy, and there is a slippery slope toward replacing the market with regulation of another kind. The Commission should act with caution not to prescribe solutions without a more careful consideration of what is required and what is possible.

INITIAL COMMENTS OF
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ON THE STANDARD MARKET DESIGN NOPR[2]
November 11, 2002

I. INTRODUCTION

The twin principles of open access and non-discrimination require fundamental change in the rules and organization of the electricity system. Under the current rules, everything from operating protocols to pricing depends to a degree on discrimination among transmission users and limitations on access to the electric grid and its essential services. When coupled with the objective of achieving an economically efficient electricity system, these principles lead inexorably to the Federal Energy Regulatory Commission's (the Commission) requirements for a standard market design. Standardization is important for the obvious effect of reducing "seams" issues between regions and markets. Less obviously, but even more importantly, certain critical

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2 These comments were prepared with the support of PJM Interconnection, LLC (PJM) and the New York Independent System Operator, Inc. (New York ISO). The authors are pleased to acknowledge the helpful critiques received from PJM and New York ISO, the two entities that operate markets most similar to the SMD. Both PJM and New York ISO generally support this submission, without necessarily adopting each of the specific conclusions or opinions expressed herein.

market activities require standardization in order to support efficient operation with open access and non-discrimination in an electricity market.

The market cannot solve the problem of market design. The Commission provides in its Standard Market Design Notice of Proposed Rulemaking (SMD NOPR)[3] an accurate description of the problems inherent in the large externalities of transmission usage and a sound solution in the application of the necessary coordination in support of a market. In each region, an Independent Transmission Provider (ITP) must administer a single tariff and operate the transmission system to support certain essential services. The critical centerpiece of the design is a coordinated spot market for energy and ancillary services. This spot market would employ the framework of a bid-based, security-constrained, economic dispatch with locational marginal cost pricing (LMP). The framework includes bilateral contracts with a transmission usage charge for each transaction based on the difference of the locational prices at the points of input and withdrawal.

This centerpiece of the SMD framework supports additional features such as financial transmission rights and license plate transmission access charges. A good design for the spot market can facilitate long-term bilateral contracting or support utilities self supplying to meet their own loads, arrangements that could constitute the bulk of energy transactions. Given the incentives from locational pricing, there is a natural market stimulus to sustain generation and demand-side investments. In addition, the creation of financial transmission rights provides further opportunities and incentives for market participants to undertake transmission expansion.

The SMD description goes beyond these basics to cover important additional topics ranging from demand-side participation, through market power monitoring, to resource adequacy. The details of these proposals and the many other features of SMD deserve and will receive attention from the Commission, state regulators, existing ISOs and market participants. In some elements there will be room for different regional tactics, with varying priorities for the speed of implementation, and some disagreement about the level of detail or the best compromises in dealing with conflicting objectives. Hence, the comments presented below and similar comments from others will be part of an important learning process in which the Commission must provide the leadership and the guidance for implementation of its proposals.

Notwithstanding our recognition of the importance of this opportunity for further tactical analysis and discussion, the Commission's consideration of comments should not be an occasion or a cause to lose sight of the most important strategic feature of the Commission's action in this SMD initiative. At great expense to the country, we have gone through an extended period of experimentation with designs for market institutions for the electricity system. There have been notable successes, as in the Eastern ISOs, as well as notable failures. These experiments have been punctuated by major decisions by the Commission, in Orders 888 and 2000, which advanced the development of an open access regime and efficient electricity markets. However, faced with sharply conflicting views across the industry, the Commission's vision has until now never been sufficiently complete or clear, and its conviction and sense of urgency have never been up to the demands of this enterprise.

As the Commission now recognizes, the notable failures in electricity markets have brought the nation to a crossroads in electricity restructuring, with some voices urging the Commission to halt or turn back out of fear that the failures will be replicated elsewhere. Learning from these failures is essential, but turning back would be the wrong lesson, and

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[3] *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, 67 Fed. Reg. 55, 452 (August 29, 2002), FERC Stats. &

standing still is not tenable. The Commission must move forward with the core elements of SMD. The nature of the electricity system requires an ITP's visible hand to coordinate the markets and assure reliability. Equally important, the present condition of the industry and the pervasive uncertainty this creates for investors require firm resolve to put the critical institutions in place at the earliest practical date, not only to clarify the industry's emerging structure but also to make transparent the incentives for investment. Only the Commission has the necessary scope of authority and responsibility to meet this challenge.

By now, the costly experiments have made plain that certain fundamentals are necessary for a successful electricity market. These are the elements at the core of the SMD framework, and the elements often absent in the failed experiments. An independent entity operating with the protocols of a coordinated real-time spot market with consistent locational pricing to reflect the actual limitations of energy availability and transmission constraints is first among these necessary elements. This by itself is not sufficient for a successful energy market. But we know from both theory and experience that it is necessary. And since it is necessary, it should be done in essentially the same way, everywhere, and soon.

The experience in the PJM Interconnection is instructive and illustrative on this point. Despite all the many advantages of PJM in its people, procedures, configuration, and history as a tight power pool, PJM demonstrated the importance of a well-designed and properly priced coordinated spot market in 1997 when it was required to go into operation without such a framework approved by the Commission. On the first hot day when demand was high, the simplistic pricing and scheduling protocols broke down and the system operator had to intervene and overturn the decisions of the market. The system operator knew that the problem originated

Regs. ¶__,___(2002).

in the flawed market design, but it had no choice absent a well-designed framework. Given this unhappy experience, with continued interventions by the system operator throughout that summer of 1997 needed to prevent the market from bringing the system down, a revised market design went into operation in 1998. The new design included the coordinated spot market with consistent pricing that in its essentials is the same design as now found in the Commission's SMD proposals. The new model worked well. Fixing the real-time market eliminated the most egregious problems and gave PJM time to consider subsequent refinements such as a day-ahead market and a multi-settlement system. The success of that design in PJM, and later in New York, complements the experience from other parts of the nation and the world in confirming the judgment of the Commission. The coordinated spot market model using a bid-based, security-constrained, economic dispatch with locational pricing works in theory and in practice. Furthermore, we would argue that it is the only such model that can support both open access and non-discrimination.

With this constant theme on the first priority to have the ITP with a workable design for the real time market, these comments focus on further details of market design, recognizing that getting the market design more or less right is a necessary but not sufficient condition for a workable electricity market. The nature of this market design is such that it creates additional opportunities for market participants and state regulators. At an extreme, individual states could continue to operate much as they have in the past, with a mix of utility ownership of generation, long-term contracts and closed retail markets. The one thing that would and must change is the elimination of closed and discriminatory access to the transmission grid. However, there are complementary measures available at the retail level that could be provided by state regulatory agencies to capitalize on and reinforce the benefits of a workable wholesale electricity market, even for states that have not chosen to pursue retail choice.

The comments below are limited to market design and closely related subjects. Important topics not considered here are state and federal legal jurisdiction, governance, and the proposed new formal method for state and federal cooperation.

II. THE COMMISSION'S NOPR CONTAINS ESSENTIAL FEATURES OF A WORKABLE MARKET DESIGN

A. The NOPR Correctly Recognizes that Workable Electricity Markets Should Support the Ability of Suppliers and Load-Serving Entities to Enter into Long-Term Supply Arrangements, Including Competitively Priced Forward Contracts, that Could Comprise the Bulk of Electricity Trading.

Much of the NOPR discusses the requirements of bid-based spot markets that would be operated by the ITP. We believe this focus is appropriate because it is the ITP-coordinated spot markets, not the forward markets, that require explicit and careful attention to market design. In some quarters, however, the attention paid to spot markets has been misinterpreted as a Commission preference for spot transactions over longer-term arrangements, including forward contracts arranged between generation suppliers (and/or marketers) and load-serving entities (LSEs). This misinterpretation may lead some to claim that the NOPR intends to discourage bilateral transactions or limit the ability of utilities and other LSEs to use their own generation to serve their own loads, an interpretation that appears to undermine traditional state utility regulation and the ability of state regulators to affect retail rates. We believe these views fundamentally misinterpret what the NOPR proposes and the Commission intends.

1. Under SMD, the foundation of power markets will support bilateral trading and self supply.

The SMD NOPR does not imply over reliance on spot markets, nor is that consequence indicative of what actually happens in those regions that have already implemented key features of the proposed standard design. In Eastern markets that provide bid-based spot markets, the spot markets support active bilateral contracting as well as utilities and LSEs that choose to schedule their own generation to serve their own loads. The bulk of energy is handled through such forward arrangements, with only a residual relying on actual spot market transactions. Most energy is therefore priced through these forward arrangements, which provide price certainty and risk management for both utilities/LSEs and generators and provide financial commitments that support essential investments in generation, demand-side options and transmission.

The Commission seems well aware of this experience. The NOPR makes clear (NOPR ¶228) that workably competitive electricity markets depend on the ability of generation suppliers (and providers of demand-side responses) to enter into voluntary long-term contracts and other arrangements with LSEs (and directly with end-use customers, in those jurisdictions that permit some form of retail choice). In stark contrast to the imposed, almost exclusive reliance on spot markets and prices that characterized California's initial restructuring rules, the Commission proposes a structure in which most electricity trading could occur through bilateral contracts of various lengths, while load-serving entities would be free to use their own generation to serve their own loads.

2. Spot markets will play an essential supporting role.

The NOPR's conceptual breakthrough, already implemented in the successful eastern ISO markets, is in recognizing the critical supportive role that an open dispatch and efficiently priced spot markets play in accommodating bilateral contracts and self-scheduling. This support is needed on a transmission network whose physical characteristics demand continuous central coordination by a system operator. Implementing bilateral transactions and self-scheduling requires that the system operator coordinate what Larry Ruff[4] and others have described as a set of integrated dispatch functions that are essential to ensure reliable operations. Performing these functions is not a policy choice; it is a necessity in every modern electricity system.

Importantly, the NOPR declares that these functions will be performed by an Independent Transmission Provider to ensure that all parties receive non-discriminatory, open access to transmission.[5] By requiring that all jurisdictional transmission be placed under the operational control of an ITP, and insisting that all grid users have open, comparable access to the ITP's essential coordination functions, the NOPR is acknowledging both the necessity and complexities of system operations that make electricity markets unique. A market based primarily on bilateral contracting and self schedules cannot function in a non-discriminatory manner unless open access to transmission is defined to include open access to the system operator's integrated dispatch functions and the spot markets they create.

3. The NOPR's focus on spot market rules is appropriate.

The NOPR's focus on spot market rules recognizes that every bilateral schedule and self schedule must be supported by an open balancing service, an effective means to manage congestion, rules for acquiring and deploying operating reserves in the event of outages, and provisions to ensure the reliability and security of the integrated network system. Because

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4 Larry E. Ruff, "Defining and Allocating RTO Functions," comments to FERC Technical Conference On Allocation of RTO Functions and Characteristics, February 19, 2002.

5 It is apparent that the successfully operating Independent System Operators in the Northeast provide the model for the ITP.

bilateral markets cannot coordinate these complex network services in the very short run, the grid operator – the ITP – must coordinate them through its integrated dispatch functions. And because resource providers incur costs in providing these services, and users rely on these functions to ensure reliable service, there must be rules to define how these parties participate and how the ITP will determine the prices paid to suppliers and charged to users.

The NOPR Standard Market Design properly focuses on the rules for the ITP's dispatch and related spot markets. Commercial rules for bilateral contracting do not rise to the level of design required in this NOPR, nor do the rules by which utilities and other load-serving entities arrange their own resources to meet their own loads. The business rules by which these arrangements are made are largely defined by long-standing commercial codes and utility practices developed over years of state regulatory oversight. The Commission is not proposing to change this, and the Commission is supporting efforts to improve business practices.

In contrast, the ITP would be a new institution, obligated to function in the public interest, independent from market participants and regulated utilities, often with multi-state transmission responsibilities, and charged with coordinating flows and transactions that necessarily implicate interstate commerce. As such, ITPs must be federally regulated.

Each ITP will need explicit rules by which it accepts schedules and bids from independent parties and arranges an economic dispatch that relieves congestion and balances the system. It will need explicit rules by which it uses the participant bids to define the prices to be paid to generators, charged to loads or assessed to parties that schedule transactions on the transmission grid. And it will need other rules for how it will arrange, deploy and price operating reserves and other ancillary services that are essential to ensure that bilateral and self schedules will result in adequate supplies and reliable delivery of power to loads.

4. A Standard Market Design is necessary.

These functions are not voluntary, nor can the rules for how they are performed and priced be voluntary. They are essential and lie at the heart of why a Standard Market Design is needed.

We see no practical alternative to establishing more or less standardized rules for these core functions. As the NOPR correctly states (NOPR ¶¶83-85), the ITP's coordination functions must work within one of the nation's three interconnected transmission networks, each operating as one huge electrical machine and spanning multiple states and Canadian provinces. It is understood that individual states cannot set different rules of the road for how these interstate electrical highways are operated or will be used. Similarly, it would be extremely difficult and inefficient for multiple operators (let alone decentralized market participants) to effectively coordinate the interconnected parts of this machine using different rules and procedures. Further, the short-run integrated dispatch functions that assure reliable grid operations are the same functions that produce short-run markets for balancing and congestion management and related markets for operating reserves. It follows that the rules for how these spot markets operate and are priced must also be standardized in line with the standard rules for system operations. The two cannot be separated and still achieve reliable operations or workable regional markets.

B. <u>The Foundation for Efficient Spot Markets is a Bid-Based, Security-Constrained, Economic Dispatch Coordinated by the ITP.</u>

The SMD NOPR proposes that each Independent Transmission Provider administer day-ahead and real-time spot markets. Consistent with the successful market designs implemented by the New York and PJM ISOs, these markets derive from a bid-based, security-constrained economic dispatch, arranged and coordinated by the ITP. We agree with the Commission that this regional dispatch is the ITP's core function and the appropriate foundation for its coordinated spot markets. NOPR ¶¶137-138.

The NOPR uses various phrases for what appears to be the same idea. For example, the NOPR discusses "security-constrained spot markets," "security-constrained, bid-based markets," "security-constrained dispatch," "bid-based security-constrained system," "bid-based security-constrained real-time markets," and so on. To avoid confusion, it may be helpful to use the same terms – *a bid-based security-constrained economic dispatch* – throughout the SMD Tariff, and to refer to the spot markets as derived from this framework. Consistent usage would not only avoid confusion about what the Commission means but also provide important guidance regarding the ITP's essential functions and how they compare to those of existing institutions.

In requiring each ITP to operate a bid-based security-constrained economic dispatch for its region, the Commission has correctly defined the components that allow the dispatch to become the foundation for workable spot markets. Under the SMD,

- The ITP's dispatch is *bid-based*, in that it is arranged from the voluntary supply offers and demand bids that reflect the willingness of these participants to participate in the dispatch and/or buy and sell energy through the dispatch at prices that are consistent with their bids. Schedules for transmission could include bids for deviations from these schedules for generation or load. Transactions arranged from offers to sell and bids to buy energy near real time are defining characteristics of an electricity spot market.

- The ITP's dispatch is *security-constrained,* meaning that it resolves congestion and ensures that flows throughout the grid remain within all security limits, while balancing the system. Hence, the NOPR recognizes that the same dispatch that provides the spot market is also the fundamental tool used by the system operator to maintain reliable grid operations. We applaud the NOPR's explicit linkage between the requirements for system reliability and the basis for the ITP's coordinated spot markets. By aligning reliability and spot markets, the SMD provides the rationale for requiring that spot market pricing be consistent with the requirements of reliable system operations – the essence of LMP. This linkage then lays a foundation for flexible market operations and efficient price signals that support the ITP's efforts to keep the lights on.

- The ITP's dispatch is *economic*, in that it represents the least bid-cost combination, given the bids of supply and demand resources, to balance the system while keeping flows within security limits.[6] Importantly, the NOPR avoids the error in some earlier designs of limiting the system operator's ability to achieve an economic dispatch, either by restricting the ability of parties to submit bids or limiting the dispatcher's ability to use the bids to find the lowest as-bid cost solutions to congestion and system balancing.

Consistent with its desire for broader regional markets, we understand the NOPR to prefer that the ITP's dispatch be *regional*. Every jurisdictional transmission system must be placed under the operational control of an ITP, but the clear preference is for very large Regional Transmission Organizations with an ITP operating the regional dispatch across the RTO's entire footprint. NOPR at ¶133. Because the day-ahead and real-time spot markets arise from this dispatch, the development of an effective regional market will require an ITP to consolidate or coordinate the dispatch across the ITP/RTO region. The NOPR apparently recognizes that regional markets cannot be facilitated if this critical dispatch function is dispersed and left to the current utility-by-utility control areas. Wherever the dispatch function may currently reside, *under SMD the critical dispatch function must move to the ITP, and the ITP would coordinate the dispatch over all transmission systems and control areas within its footprint*.

This is an important message to those forming new ITPs and RTOs, as it focuses attention on what the necessary transition requires and how long it may take. The relatively easy creation of bid-based spot markets from existing power pools that had already integrated a security-constrained economic dispatch across multiple transmission systems is done; the hard task of converting other regions with multiple control areas to a coordinated regional dispatch under an ITP/RTO is the task at hand. Current efforts to establish large RTOs in the Eastern Interconnection and the Pacific Northwest are an indication that many parties understand this necessary transition and are moving in the right direction.

An important aspect of the security-constrained economic dispatch is that it enables integrated spot markets for both energy and transmission. Under the SMD, parties can in effect buy and sell spot transmission, just as they can buy and sell spot energy, to support their commercial transactions, with the integrated spot markets defining consistent prices for spot transmission and energy. The Commission and participants have learned from the unsuccessful attempts to separate energy and transmission markets that these are inseparable.[7] Rules and structures that artificially separate energy and transmission invariably lead to inconsistent pricing, inefficient grid usage, infeasible schedules, cost shifts and strategic gaming.

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6 The "least cost" terminology is a carryover from consideration of generation only. With demand bids an economic dispatch maximizes the bid-based net benefits of supply and demand.

7 William W. Hogan, "A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy," Electricity Journal, December 1995, pp. 26-37.

The NOPR's integrated dispatch and spot markets implicitly recognize that (1) scheduling transmission between two points and paying the congestion-related dispatch costs and (2) selling energy at one point and buying it at another are functionally and financially equivalent ways to achieve the same physical and commercial objectives. Recognizing this equivalence and insisting that the two be connected through the same dispatch and priced on a consistent basis is a major advance over previous notions of how transmission service should be provided to support commercial trading.

C. The Real-Time and Day-Ahead Dispatch/Spot Markets Will Be Efficiently Priced Using LMP.

The NOPR's strong endorsement of locational marginal pricing is well founded. It is based on several years of successful experience in LMP-based systems by the New York and PJM ISOs and universally unsuccessful experiences with alternative pricing approaches ranging from uniform pricing (PJM in 1997, and New England) to zonal pricing (California and Texas). ISOs that began with non-LMP approaches, including PJM, New England and California, eventually concluded that these approaches were fundamentally unworkable and incompatible with reliable operations and flexible market operations. These histories are by now well known and the lessons are consistent. Every ISO (except Texas/ERCOT, where LMP is under consideration) is now either using LMP or moving to implement LMP at the earliest practical date.[8]

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[8] See, "Joint Comments of the North American RTOs and ISOs," to be filed in this Docket.

LMP applies economic principles of marginal cost pricing to energy and congestion management. It is consistent with market outcomes under competitive conditions.[9] In the absence of congestion, LMP defines the market-clearing prices across the region. In the presence of congestion, LMP applies these principles to price the effects of congestion on transmission usage, so that spot energy transactions and bilateral schedules pay (or receive) the marginal costs of any redispatch that may be required to accommodate a transaction on a congested grid.

The advantages of LMP extend beyond the theoretical coherence to pragmatic support of reliable system operations. By pricing the system operators' (ITP's) actual dispatch at marginal costs, LMP aligns the price signals given to those participating in the dispatch with the tool the ITP uses to keep the lights on. Under LMP, the price signals tend to encourage parties to follow the dispatch – that is, to do precisely what the system operators need them to do to support reliability.

Including marginal losses in LMP prices will improve the efficiency of the price signals and provide better incentives for generation and demand-side investments. This will tend to encourage new resources to locate closer to loads, including distributed generation and other behind-the-meter options. At the same time, including marginal losses in LMP prices will also make transparent the fact that generation at some locations actually reduces marginal losses on the system. This transparency should improve both siting decisions and the efficiency of the ITP's dispatch.

The Commission recognizes that use of marginal losses follows from the same principles as any other marginal cost. However, the Commission asked for comment on the possible use of

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9 F. C. Schweppe, M. C. Caramanis, R. D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity*, Kluwer Academic Publishers, Norwell, MA, 1988. W. Hogan, "Contract Networks for Electric Power

average losses on the grounds that this might be simpler. NOPR ¶ 267. The argument based on simplicity is misplaced. It is true that pricing according to marginal losses will produce a revenue surplus relative to the average cost of losses. But this is no different than the condition for energy where the average incremental cost of generation is less than marginal cost, and the same is true with congestion. It is fundamental to efficient operation with increasing variable costs that the marginal cost is higher than the average variable cost. And it is fundamental to markets that average cost pricing is both inefficient and administratively difficult. With average cost pricing there is no way to preserve efficient incentives or to identify who bears the cost responsibility for the average cost. The apparent simplicity would be illusory if the costs were significant. For the same principled reasons that the market should use marginal not average costs for energy and congestion, marginal cost pricing should be used for losses wherever they are significant. The more that losses matter, the more important it is to use marginal cost pricing. The revenue surplus can be used to reduce uplift charges or transmission access charges, and should be allocated in a manner disconnected from marginal consumption.

Marginal losses are currently included in the Location-Based Marginal Prices (LBMP) in New York but are not included yet in the LMPs in the PJM market. There are important efficiency benefits to moving to marginal losses, so including this feature in the SMD as part of the eventual end state is warranted. However, these benefits should be weighed against the value of other reforms that must be undertaken to implement the core features of SMD. In the United States, losses may not be the most important issue, and the timing of the reform becomes a matter of priorities.

Transmission," *Journal of Regulatory Economics*, Vol. 4, 1992, pp. 211-242.

Whether the issue is marginal losses, day-ahead markets, simultaneously optimized markets for operating reserves, or some other advanced feature, each region will need a phased approach. Implementing all of the features at once is probably not practical. Full implementation of the SMD represents a major undertaking with significant software and other technical challenges. Given the demands on software design and implementation, even LMP-based regions like PJM and New York will have to choose between expanding the geographic reach of their real-time markets – an obvious priority – and enhancing existing market systems to include both day-ahead and real-time markets for reserves, marginal losses, fully co-optimized reserve markets or some other feature. Given that some regions have ISO-coordinated markets while others do not, each region may have different priorities depending on how much their existing systems differ and must be modified. For this reason, once the direction to develop LMP-based real-time markets is clear, we recommend that the Commission give ITPs/RTOs sufficient flexibility to propose appropriate phasing of the more advanced features of LMP-based systems, given the priorities defined in their respective regions.

D. Under SMD, Spot and Bilateral Transactions Will See Comparable Charges for Transmission Use, Reflecting the Marginal Costs of Any Redispatch (and Losses) to Relieve Congestion.

An advantage of the SMD's use of LMP is that it will allow all transactions to be priced on a consistent, comparable basis. Generators participating in the dispatch or selling into the spot market will receive the LMP for injections at their locations; loads participating in the dispatch or purchasing from the spot market will pay the LMP for withdrawals at their locations. The spot market volumes may be much less than the total load, with much of the final dispatch arranged through bilateral schedules. To ensure comparable pricing between spot energy transactions and bilateral (transmission) schedules, transmission schedules will pay usage charges defined by the difference between the LMP at the sink and the LMP at the source. Thus, for a transmission schedule from location A to location B,

$$\textit{Transmission usage charge} = \textit{MW Quantity X } (LMP_B - LMP_A)$$

This principle recognizes that the market value of transmission between any two points is equal to the difference in the market prices at those two points, reflecting the logic that a party would never pay more for transmitting power between locations A and B than it would cost to purchase the power at B rather than A. Applying this principle, it becomes apparent that parties that sell power at A and purchase it at B would achieve exactly the same financial result as a party that schedules transmission from A to B and pays the usage charge. This exact comparability means that the ITP can be indifferent to whether parties engage in bilateral transactions and pay usage charges or sell and buy spot energy at their respective locations.

An advantage of this approach is that the spot markets coordinated by the ITP would accommodate a wide range of commercial freedom without undermining reliable operations. NOPR ¶207. Parties can buy and sell in the spot markets, schedule bilaterals (and use the dispatch/spot markets for balancing), schedule generation without load and loads without generation, schedule own generation to own load, and so on. Each transaction pays the marginal costs of its grid usage, fulfilling the principle that all users receive open, non-discriminatory access to the grid.

E. The SMD with Locational Pricing Does Not Interfere with State Authority Over Retail Rates.

The use of LMP ensures that there will be efficient locational price incentives at the wholesale level. However, despite misplaced concerns about the loss of state prerogatives, the

SMD NOPR is not proposing to infringe on the traditional rights of state and local regulators to determine how wholesale prices will be reflected in retail rates.

The NOPR correctly acknowledges that load-serving entities that purchase energy from the spot markets will probably pay aggregate prices composed of the load-weighted average of the nodal LMP prices for a region. Given the experience in the East, the most likely aggregation is by utility service area, as defined by state regulators. While any averaging scheme introduces inefficient incentives, some aggregation is unavoidable because there is at present insufficient metering to determine the hour-by-hour allocation of withdrawals at every node and because most existing legacy billing systems cannot handle billing for smaller customers on a nodal basis. Larger customers, particularly those connected at higher voltage levels (or directly to the transmission system), are usually supported by interval meters and billing systems and so can (and should) be allowed to receive nodal prices. Because of the importance of encouraging efficient demand response to prices, a transition to move customers toward this approach should be part of the defined end state for the Commission and state and local regulators.

An LMP-based system creates the opportunity for state and local regulators to improve the efficiency of rate design and enhance the ability of LSEs and retail consumers to invest in and initiate demand-side responses. Efficient demand-side response is now generally acknowledged to be a critical element in workable markets, because it can limit the effects of shortages and mitigate market power, while giving consumers meaningful control over their electricity bills. Under SMD, efficient real-time pricing becomes possible because the LMP-based wholesale prices provide the proper basis for pricing energy usage at the margin. But these would be matters for state and local regulators to decide.

F. The SMD Appears to Allow Open Access to the ITP-Coordinated Spot Markets with a Minimum Reliance on Administrative Restrictions and Penalties. This Approach Will Allow Flexible Grid Use and Help Ensure Efficient Results While Supporting Reliable Operations.

1. The SMD supports market flexibility and reliable operations.

We understand the NOPR to mean that under SMD, once LMP pricing is used, the extent to which parties rely on the spot market or on forward transactions can be left to the participants to decide. We support this flexible approach. There need be no restrictions on or penalties for spot market usage other than those necessary to ensure that parties that subject themselves to the dispatch follow dispatch instructions closely enough in real time to ensure reliable operations. In some regions, the LMP prices may be sufficient for this purpose and no penalties would be required. FERC should allow regional flexibility on this point.

Once spot prices are aligned with reliability imperatives, parties can choose between ITP-coordinated spot transactions and forward bilateral transactions, between submitting to the ITP dispatch and self-scheduling, and between following forward schedules or deviating to rely on economically attractive opportunities presented by the spot markets. In the absence of LMP, allowing this flexibility could present problems for the ITP, either by compromising reliable operations or shifting costs to others by “leaning” on the system. Under LMP, there is no “leaning,” because every party pays (or receives) the marginal costs that its transaction imposes on the system. LMP consistently applies the principle of assigning costs on the basis of causation.

2. The SMD correctly avoids requiring balanced schedules.

The SMD appears to recognize that individual parties should be free to offer or schedule generation without loads and to bid or schedule loads without generation – so called "unbalanced" schedules. NOPR ¶¶48-49. Once the ITP's dispatch and associated spot markets are open and efficiently priced at LMP, any rationale for a "balanced schedule" requirement disappears. Through its bid-based security-constrained, economic dispatch, the ITP has the tool it needs to maintain a balanced system that respects all system security limits. While maintaining an aggregate system balance is a reliability necessity, individual balanced schedules are neither necessary nor desirable. Indeed, under the SMD, imposing individual balanced schedule requirements could undermine the flexibility the ITP needs to adjust generators and loads to ensure reliable operations through the security-constrained, economic dispatch. That is, reliable operations are more likely under SMD in large part because the ITP's dispatch is not encumbered by the restrictions of having to submit and maintain balanced schedules.

Proposals for balanced schedule requirements usually arise from one of two motivations. First, there is a holdover from the old physical scheduling tariff rules that seem like a natural requirement to continue in the market design.[10] However, a close examination reveals that this is not a natural requirement at all, as evidenced by the treatment of network service or the old operations of power pools. The only natural requirement is for balance in the aggregate, and this is provided through the coordinated spot market. Second, some markets have been designed with the explicit intent to minimize the activities of the system operator and prevent market

[10] In the absence of SMD and LMP, utility operated control areas typically insist that other parties submit and maintain balanced schedules. This reflects the fact that they do not provide open, comparable access to their dispatches and do not efficiently price use of the dispatch for balancing. Without efficient pricing, "leaning" on the control area dispatch can be a legitimate concern for the transmission owner or system operator. These concerns no longer apply under SMD with LMP. Hence, the NOPR is right to allow participants to choose balanced schedules but not have the rules require them.

participants from trading through the coordinated spot market. For example, this was the case in California, with its embrace of the separation fallacy that produced the California Power Exchange separate from the California Independent System Operator. As the Commission knows, the end result of this type of restriction is to reduce the flexibility of the market, especially during tight conditions, and to force the system operator into more and more non-market administrative interventions to undo the problems that result.[11]

Hence, a balanced schedule requirement produces no good result. The requirement is at odds with both the requirements of reliability and efficient market operation. A balanced schedule requirement creates barriers to entry for smaller market participants who do not have the sufficiently sized portfolio to internalize their own imbalances. A balanced schedule requirement creates incentives to game the rules by submitting false schedules, creates the need for countervailing penalties, and is a hallmark of a badly designed electricity market.

Once the need for balanced schedules is eliminated, large and small generators are free to sell any part of their output through bilaterals or through spot sales; loads are free to purchase any part of their requirements through bilaterals or through spot purchases. Generators with bilaterals are free to respond to dispatch signals and spot prices, voluntarily replacing their own generation with less expensive spot purchases whenever it is economic to do so. Similarly, loads are free to follow their forward schedules, to use more energy by purchasing it at spot or to use less energy and selling it back at spot. In other words, flexible use of the spot market enables

[11] A corollary principle is that states should avoid forcing their regulated utilities to serve their loads exclusively through balanced schedules. Such restrictions would not improve system reliability but could undermine the ITP's ability to ensure reliable operations.

exactly the kinds of supply-side and demand-side responses to prices that promote reliability and enhance market efficiency.[12]

3. The SMD facilitates bilateral contracting and self-supply arrangements.

With the SMD structure, parties can arrange bilateral transactions at any time, but they need not "schedule" their bilateral transactions with the ITP in advance. Parties that may already have bilateral contracts can still "schedule" them with the ITP, but they can also deal with the ITP before the dispatch solely through offering to sell and buy at spot, then ask the ITP after the dispatch to combine and net out their settlements. The net effect of selling at A at the spot price and buying at B at the spot price is financially the same as a bilateral schedule from A to B that pays the usage charge. Parties are thus allowed the flexibility to arrange and reveal their bilateral contracts at any time up to the deadline for submitting settlement information, which may be a day *after* the actual dispatch for their transactions.[13]

The SMD structure thus accommodates flexible bilateral trading while allowing parties to participate in the dispatch and to be responsive to the prices that arise from the dispatch-based spot markets. Under SMD, bilaterals become a highly flexible financial mechanism to lock in prices and allocate risks between contracting parties, but they do not become a physical constraint imposed on the dispatcher's ability to ensure reliable operations.

Of course, under the SMD a market participant could choose to restrict itself to self-supply in a more traditional mode. There is no requirement to use the facilitated trading

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12 For example, a load or LSE can purchase energy forward (e.g., in the day-ahead market) and then decide whether to sell any or all of this pre-purchased energy back in the real time-market, if it determines that the real-time spot prices exceed its willingness to pay to take the energy. The reduced demand would of course tend to push spot prices lower, even if there were no explicit demand bid.

13 For purposes of arranging the security-constrained economic dispatch, the ITP need only know the grid locations and amounts of expected injections and withdrawals. At the time of the dispatch, the ITP is

available through open access and non-discrimination. The effect of the SMD, therefore, is to provide expanded opportunities for operating the system and to foreclose the possibility that others would be precluded from using the transmission system.

G. <u>The ITP Will Offer Financial Transmission Rights in the Form of Point-to-Point Congestion Revenue Rights.</u>

The NOPR proposes to require each ITP to offer a form of "financial" transmission rights, which would be called Congestion Revenue Rights, or CRRs. Although CRRs could take several forms, we understand the initial CRRs to be essentially the same as the Fixed Transmission Rights (FTRs) used in PJM and the Transmission Congestion Contracts (TCCs) used by the New York ISO. NOPR ¶240. Subsequent extended versions of CRRs would include options and flowgate rights, if requested by market participants and once the capability to manage these additions has been developed. This staged approach is appropriate for implementation of CRRs. However, the NOPR proposes additional uses for CRRs that the Commission should not adopt.

As defined in the NOPR, and similar to PJM's FTRs and New York's TCCs, the CRRs are primarily financial hedges that give the holder a right to a stream of revenues from the congestion charges accumulated in ITP's spot market settlements. These "obligation" rights define the settlement value of each CRR by the difference between the LMP congestion prices at the two points indicated in the CRR.[14]

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indifferent to whether a set of injections and withdrawals is commercially connected through a bilateral contract. This information is relevant for settlements after the dispatch.

[14] Like FTRs and TCCs, these CRRs are point-to-point and directional, defined as from one bus or node to another bus or node on the grid. The settlement value of a CRR from location A to location B is thus the LMP at location B minus the LMP at location A. If marginal losses are reflected in the LMP prices, then the difference is based on the congestion-related component of the respective LMP prices, exclusive of marginal losses. Full LMP prices can be decomposed into a congestion-related component and marginal losses component relative to a reference location. Hence, the rule in New York, which includes marginal

Holders of CRRs would thus have a financial hedge against uncertain congestion (usage) charges and locational price differences defined by LMP. Parties could use CRRs to lock in the price of transmission in advance and assure the delivered price of energy at any location. More sophisticated uses would allow parties to sell "negative" CRRs in advance, which is equivalent to selling congestion management services forward (and creating forward markets for congestion management services).

1. The SMD should avoid giving CRRs a "physical" aspect.

Unlike FTRs and TCCs, the NOPR's proposed CRRs would also have a physical aspect that would give resources or schedules backed by CRRs a physical priority on the transmission grid. In our view, giving CRRs a physical aspect would be a mistake. It would, in effect, reintroduce the problems of balanced schedules summarized above, but with even less flexibility in the precise circumstances where the system is constrained and redispatch is necessary.

A principal advantage of defining transmission rights as financial hedges is the ability of parties to accomplish their commercial objectives while giving them the flexibility to achieve efficient operations. In addition, purely financial rights allow the ITP to arrange an efficient dispatch, without requiring final schedules to match CRR holdings.

Given the advantages of financial rights, the NOPR's proposal to assign CRR holders scheduling priority in the event that redispatch is not available is problematic and is not needed in any event. The more "physical" the rights become, the more parties will be induced to match their CRRs to their anticipated and actual schedules. While this might spur increased CRR trading, it is artificially induced trading for its own sake, without providing additional value to

losses, is that TCCs hedge congestion costs but do not hedge parties for LMP differences attributable to marginal losses. PJM FTRs also hedge congestion costs, because marginal losses are not included in the

the market. Rather, an artificial inducement to match schedules and rights would only add to the costs of trading and scheduling. Alternatively, it could induce parties to avoid otherwise economic trades (and worthwhile changes in injection and withdrawal points) merely to avoid the necessity of further trading to find matching CRRs. In the meantime, a physical aspect would tend to discourage parties from participating in the dispatch and offering the ITP the flexibility it needs to ensure reliable operations in the face of congestion. We see no useful purpose in adding a physical aspect to CRRs, and clear reasons to avoid it.

Some rule will be needed to handle emergency conditions in which there are insufficient bids to relieve congestion through redispatch, so schedules must be curtailed to relieve the constraints. However, there is no reason to assume that those who choose to hedge congestion by matching CRRs to schedules place any greater value on their schedules than those who acquire portfolios of unmatched hedges or no hedges at all. Moreover, giving matched CRR holders priority would not always solve the curtailment problem, because it is likely that few parties will exactly match final schedules and CRR holdings. In the event that redispatch were not possible, and the CRR priority rule did not solve the problem, the ITP would still need another rule, such as *pro rata* curtailment, to decide which schedules to curtail to relieve congestion. Since some other rule is needed in any event, there is no need to encumber CRRs with a physical aspect.

The same disadvantage with respect to giving CRRs a "physical" aspect applies to ensuring capacity "deliverability," where there is even less connection between the designation and deliverability of capacity resources and the acquisition of CRRs. See NOPR ¶514.[15] A CRR

PJM LMPs. These are probably second order differences in design that need not be resolved in the SMD.

15 The NOPR may have confused CRRs with the "deliverability rights" used in PJM. In PJM, generators that expand the grid's capacity to ensure deliverability of their capacity (in order to receive capacity credit) receive a property right to maintain that deliverability. In theory, this right works by requiring that

cannot ensure physical deliverability. If a resource adequacy requirement is imposed, some form of capacity deliverability right may be needed if resource requirements are not locational, as they are in New York, but CRRs cannot and should not be used for this purpose.

2. The Commission should provide regional flexibility in how CRRs are initially offered to the market.

The NOPR anticipates an initial allocation of CRRs and asks for comment on the appropriate principles to apply in deciding which entities receive the CRRs. Some type of allocation is a necessary step at the start of any LMP-based market. The goal here is to provide an acceptable transition that converts the net effect of entitlements, rights and responsibilities in the current system to an acceptable position under the new design without compromising the basic market principles or significantly distorting the incentives going forward. One means is to allocate to parties either CRRs or the auction revenue rights (ARRs) that would be received if all of the simultaneously feasible CRRs were auctioned.

The distinction between ARRs and CRRs is small, addressing only the explicit or implicit integration with an auction for the entire existing grid. Any initial allocation of CRRs could stand alone or could be accompanied by an auction for the entire system in which these CRRs could be offered for sale. However, there has been a concern that regulatory incentives or inertia would inhibit initial recipients of CRRs from trading in the market, foreclosing the intended liquidity in the initial auction. The idea arose to create ARRs, which are, in effect, equivalent to CRRs that must be offered in an auction. Hence, the auction would include the full capacity of the grid. Of course, the holder of any ARR could convert the ARR to an equivalent CRR by

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subsequent capacity resources also provide sufficient grid expansions to ensure their own deliverability and not erode the deliverability of previously designated capacity resources. However, these deliverability property rights are not FTRs, which function only as financial hedges.

making a sufficiently high bid in the auction. Winning the CRR would require a payment at the auction price exactly balanced by the revenue on the ARR. Therefore, the net effect of the ARR approach makes all bids for the CRRs explicit in an auction. While there are arguments for either approach, in theory the parties that would be entitled to receive the CRRs through prior allocation are exactly the same parties that would be entitled to receive the corresponding ARRs.

The NOPR recognizes that the number of CRRs or ARRs that can be defined is limited by the transfer capability of the transmission grid and that any allocation (or auction) should be limited by a simultaneous feasibility test. NOPR ¶253. The greater the transfer capability, the greater the number of CRRs (or ARRs) that can be defined while still assuring the ITP's ability under normal grid conditions to fully fund the CRR settlement payments.

Though they differ in initial allocation approaches, both New York and PJM have sought to apply a common principle in allocating TCCs, FTRs, or ARRs. That principle should be applied to CRRs. The principle is:

> *Those who have been paying and will continue to pay the costs of grid facilities should receive the benefits of an allocation of CRRs or ARRs.*

While straightforward in concept, this principle is not easy to apply. For the same reasons that give rise to externalities in the grid and the need for the SMD, there is no simple connection between the costs of the grid for specific components and the resulting transmission capability these create. Each set of facilities (or expansions) can accommodate many different sets of CRRs. In addition, there may be competing claims for CRRs that cannot be simultaneously accommodated. These difficulties warrant further efforts to find workable approaches to treat expansions.[16] For the existing grid, where the costs have already been

[16] See, e.g., Scott Harvey and Susan L. Pope, "MSWG Expansion TCC Approach, Revised," NYISO Market Structures Working Group, November 15, 2001, for a discussion of related issues.

incurred, there is no unique allocation rule available. Hence, the Commission should anticipate negotiated multiparty agreements with the ITP providing technical assistance and FERC being the final arbiter. There is no reason to expect or require that the allocation rule be the same in each region. What is important, however, is that there be some allocation of the CRRs associated with the existing grid, or the equivalent ARRs, in order to support the rest of the SMD. In regions where this has already been accomplished, as in PJM and New York, there is no reason to disturb the existing agreements.

This principle provides a consistent guide for allocating both rights to the existing grid and rights to grid expansions. That is, those who fund grid expansions that increase the grid's transfer capability should be allocated a feasible set of net incremental rights made possible by their expansions. This is (or should be) the same principle that underlies the concept of "participant funding" of transmission expansions.

Participant funding, where the beneficiaries of investment pay the costs, should not merely be permitted; it should be expected from those likely to benefit from grid expansions. But those who provide the funding should receive the increased grid value they create through the award of incremental CRRs. This implies that rolled-in rates for grid expansions that are spread broadly across grid users (primarily loads under SMD) should be used only where participant funding of economically justified investments is not likely because of market failure, and where likely beneficiaries cannot otherwise be identified or the benefits are so pervasive (as might occur with some upgrades essential to system wide reliability) as to make more selective allocation of costs to beneficiaries impractical.

This principle is not the same as allocating rights based on historic usage. It may often be the case that historic usage includes unscheduled parallel flows that have traditionally gone uncompensated under the existing contract path scheduling approach. For example, parties with contract path rights may not be contributing to the embedded costs of other systems on which there are parallel flows. Each region will have to address how best to accommodate any equities associated with claims of historic uses without significantly undermining the important principle that those who pay for the grid should receive its economic value.

There will be no simple answers to these allocation questions in the regions. The SMD is on the right track of the general principle, which tries to match benefits and costs. But the particular implementation may necessarily differ in different regions.

3. While CRR auctions would allow for an efficient allocation of rights, the Commission should allow each region flexibility in deciding how soon to move to CRR auctions and how to structure those auctions.

The NOPR anticipates that ITPs would eventually administer periodic bid-based auctions of CRRs. These auctions will help ensure efficient allocation of CRRs and provide for reconfiguration of previously allocated CRRs, thus helping parties align their congestion hedges with their risk management needs.[17] An auction mechanism for all CRRs would also increase liquidity by avoiding any unintended regulatory incentives to withdraw allocated CRRs from the market. The Commission indicates a willingness to allow regions to defer auctions for an initial period while parties gain a better sense of possible CRR values.

Any auction proposal presupposes an agreed-upon approach for allocating the auction revenues. Thus, before moving to auctions, each region must agree on some ARR allocation method, guided by the foregoing principle that those who pay the fixed costs of the grid receive

[17] For example, periodic reconfiguration auctions can be used to acquire and adjust portfolios of CRRs that provide the aggregate level of risk management that each party seeks, given the aggregate exposure to congestion costs from expected energy transactions. Parties would be free to pursue CRRs that match expected schedules, but the rules need not require that.

the benefits through an allocation of CRRs or ARRs.[18] Hence, choosing to have auctions does not avoid the allocation issues; it requires they be addressed.

The NOPR proposes to require ITPs to first offer point-to-point CRR obligations and defer offering CRR options and/or flowgate rights until issues of simultaneous feasibility and market need are established. NOPR ¶248. This proposal builds on established, workable approaches. It recognizes that simultaneous feasibility is essential to ensure proper funding of the CRR hedges and that these issues are not fully resolved for other forms of CRRs.[19]

4. The Commission should not require ITPs to provide on-demand reconfigurations of CRRs.

The NOPR proposes that the ITP allow CRR holders to exchange ("reconfigure") their CRRs on demand. NOPR ¶252. There are problems in implementing this concept and it is not needed in any event. On-demand reconfiguration could lead to first-come, first-served requests to acquire all remaining CRRs not taken in an auction or allocation process, but without any method to ensure an efficient allocation based on willingness to pay, as would occur in an auction. Each request would need to be subject to a simultaneous feasibility test to ensure the ITP's continuing ability to fund all outstanding CRRs.

Trading of existing obligation CRRs, or even decomposition to and from trading hubs, could occur at any time without requiring participation by the ITP. Hence, there would be substantial opportunities to rearrange portfolios of CRRs. But absent a formal reconfiguration auction, an "on demand" request to reconfigure CRRs would be like asking for exchange of capacity on one pipeline for capacity on another. There would be no simple rule for deciding on

[18] This could occur through direct allocation of the ARRs to those paying for the grid, or through the use of the ARR revenues to reduce transmission access charges.

equivalence, and the ITP would be soon pressed to consider other requests simultaneously – in other words, to hold a reconfiguration auction. It is not clear what benefit this "on demand" proposal would produce that cannot be achieved through periodic auctions and the NOPR's proposed day-ahead market.

Under the SMD, the day-ahead market and LMP-based settlement process provide the equivalent of automatic reconfigurations of CRRs every day without raising any of the issues in on-demand reconfiguration. In the day-ahead market settlements, parties holding CRRs "cash out" their CRRs, receiving their market value based on the day-ahead LMP prices. These settlements occur whether or not the parties actually schedule transactions matching their CRRs (or any schedules at all). This is equivalent to the parties selling their transmission rights for those hours in the day-ahead market and receiving the market value, based on day-ahead prices. In the same settlements, parties that schedule transactions in the day-ahead market pay a usage charge that reflects the marginal cost of any redispatch required to accommodate their schedules. Again, these schedules need not match the parties' original CRRs. Paying the usage charge is equivalent to buying new transmission rights that match the schedules for those hours, at the day-ahead prices. In effect, therefore, the day-ahead market and settlement allow parties to reconfigure their rights: they turn in and are compensated for the CRRs they hold, and they receive and pay for the equivalent of CRRs for the schedules they submit, as though they had exchanged one set of CRRs for another set that now matches their day-ahead schedules. Since these day-ahead reconfigurations can occur every hour for each day-ahead market, there is no need for further on-demand CRR exchanges in the spot market.

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[19] William W. Hogan, "Financial Transmission Right Formulations," Center for Business and Government, Harvard University, March 31, 2002.

Periodic auctions would provide additional reconfiguration opportunities for longer-term CRRs. These are conducted on a monthly basis. The issue, therefore, should not be seen as a need for "on demand" reconfiguration. It would be better to cast the question in terms of the need for more reconfiguration auction opportunities between the day-ahead and monthly cycles. Any request for "on demand" reconfiguration that could not be accommodated in the recurring CRRs reconfiguration auctions or the day-ahead schedules should face a burden to demonstrate that it does not actually create more problems than it solves.

5. The Commission should allow alternative approaches for ensuring CRR revenue adequacy.

The NOPR proposes that transmission owners be liable for CRR revenue shortfalls. However, other approaches would also be compatible with the core of the SMD and a single standard approach is probably unnecessary, at least until inter-regional CRRs become available. For example, revenue surpluses can be carried over and applied to revenue shortages, for defined periods. If shortages remain, CRR funding can be adjusted *pro rata,* as in PJM.

An attraction of the SMD framework is in a connection to providing incentives for transmission owners to maintain the transmission grid and provide innovative methods to increase transmission capacity. Transmission owners could be liable for shortfalls resulting from the failure to maintain the grid but would also be eligible for incentive payments for achieving superior maintenance. The Commission should be open to such innovative incentive proposals. However, there has been little attention given to the exact structure of such incentives and how they would interact with other elements of the market design. For example, while it would be useful to provide incentives for effective maintenance, making the transmission owner liable for all CRR revenue shortfalls would conflate at least two activities over which the transmission owner had no control. A revenue shortfall could arise from the actions of the ITP, or a revenue shortfall could arise because of events like earthquakes not normally associated with maintenance deficiencies. Deciding on the proper balance of liability, allocating individual responsibility for multiple system failures, and providing the positive incentives as well as the negative penalties should be priority items for the attention of SMD development. However, while appropriate to point in this direction, it would premature for the SMD to decide on these details or to impose a single model without further deliberation.

III. THE COMMISSION IS CORRECT IN PROPOSING TO UNIFY TRANSMISSION ACCESS UNDER NETWORK ACCESS SERVICE.

A. Network Access Service is a Major Advance Over Previous Notions of Transmission Service.

The NOPR indicates that the SMD's new transmission service, to be called Network Access Service (NAS), "builds upon the existing Order No. 888 Network Integration Transmission Service…" and combines beneficial features of existing network integration service and point-to-point service. NOPR ¶139. We agree that the new Network Access Service combines the best features of the two existing services and agree that a unified framework will be beneficial to the industry. Moreover, there is a fundamental distinction between the Order No. 888 framework and SMD, and many of the important benefits of SMD arise from this difference.

1. Network Access Service remedies a principal defect in Order No. 888.

Under Order No. 888, firm point-to-point service is generally available only to the extent that a transaction can be accommodated within existing grid capacity – available transfer capability (ATC) – without requiring any further redispatch of generation.[20] If studies performed in conjunction with transmission service requests indicate that redispatch might be required, firm service need not be granted unless the user agrees to pay for upgrades to allow the transaction to flow without redispatch. If no upgrade is made, then only non-firm service can be granted. In that event, there is no obligation on the part of the system operator to redispatch – to arrange a security-constrained dispatch – to accommodate the service request, even though in most cases redispatch could easily accommodate the transaction.

The Commission recognizes that this is a major drawback of the Order No. 888 framework. NOPR ¶75. Because there is no means to efficiently price redispatch absent the SMD, system operators will not willingly incur the costs of redispatch to support transmission service requests. The inability to offer an efficiently priced redispatch can result in the exclusion of transactions from the grid, even if the transactions would have been economically justified if the customer were required to pay the marginal costs of any needed redispatch. Order No. 888 can thus leave the grid significantly underutilized, or utilized only by non-firm schedules whose delivery is uncertain. And because it has no logical mechanism to price redispatch, Order No. 888 has no way to allocate grid usage efficiently to those willing to pay for redispatch.

The important advance of the SMD over Order No. 888 is that the Independent Transmission Provider will arrange redispatch – through a bid-based security-constrained economic dispatch – to accommodate every request for transmission service and then price and charge for that redispatch using LMP. That is apparently what the Commission means when it says that,

[20] Here we define "redispatch" as resulting from a bid-based, security-constrained economic dispatch, arranged in one integrated process to relieve congestion and balance the system. It is not a "second dispatch."

> "Where there are transmission constraints, the LMP system we propose will price out all transactions and redispatch available generation as needed to accommodate all requests for service." NOPR ¶ 140.

Under the SMD, the ITP will provide redispatch as long as there are sufficient bids to arrange a security-constrained, economic dispatch and as long as the transmission user agrees to pay a usage charge reflecting the marginal costs of that redispatch, as defined by the differences in locational prices. By unifying all transmission service under Network Access Service, the Commission is in essence saying that all transmission use will be supported by the ITP's security-constrained, economic dispatch and its associated spot market pricing. This is a fundamental change from the operating philosophy that underlies Order No. 888.

2. The Commission is correct to unify transmission service under Network Access Service and provide all grid users equal access to that service.

Because the ITP will arrange redispatch for all transmission requests, and then apply consistent LMP-based usage charges to every proposed grid use, all grid users will be treated in a comparable, non-discriminatory manner. This is not possible under Order No. 888 because some users (e.g., certain network customers and native loads) receive the benefits of a dispatch service (and redispatch for congestion) but other users (point-to-point customers) do not. The Commission can thus unify transmission service under NAS and eliminate discrimination because all uses of the grid are supported through equal access to the ITP's dispatch and its associated spot markets. We therefore agree with the NOPR's basic conclusion, already suggested in Order No. 2000, that non-discriminatory access to transmission requires open, non-discriminatory access to the system operator's dispatch, with associated spot markets priced at LMP. An efficiently priced spot market based on a security-constrained, economic dispatch and settled at nodal prices, was the missing component in the Order No. 888 framework that prevented the Commission from achieving its statutory mandate of non-discriminatory open access to the nation's grid.

The Commission has correctly concluded that to ensure non-discrimination, the ITP must provide and price its grid coordination services to all grid users/customers on an equal basis. We agree that eliminating the distinctions for non-native loads is necessary to achieve non-discriminatory open access and efficient use of the grid. However, we do not interpret this as eliminating a "preference" for "native loads" if that implies denigrating the service that native loads receive. Rather, we see the SMD as a proposal to expand and extend the benefits of truly open transmission service to all loads and grid users.

It would not make sense to transfer operating control of the grid and the integrated dispatch service to an Independent Transmission Provider only to have the ITP itself treat some users in a discriminatory fashion. In states with retail choice, the need for equal access to an ITP's network coordination services is obvious. Non-discrimination would require that there be no distinction between "native loads" served by the residual utility or default provider and "native loads" served by competitive LSE/retailers. But the logic of equal access applies even if states do not have retail choice. All electricity consumers are ultimately "native" loads, and all loads are increasingly served by a combination of utility-owned resources and independently owned resources. In the aggregate, final consumers cannot possibly benefit from rules that allow only some of their demands to be met by those who get preferential treatment in terms of grid access while the remainder of their demands are met by resources whose access to the grid is subject to discriminatory treatment and other barriers to entry.

3. Network Access Service properly replaces the outmoded "contract path" approaches of Order No. 888.

SMD also represents a conceptual break from the transportation analogies that underlie the existing *pro forma* transmission tariffs. Under Order No. 888, the transportation terminology sustained the unrealistic concept of contract path scheduling, as though electrons would be physically delivered from "point of receipt" to "point of delivery" along a specific path selected by the scheduling party. *Pro forma* tariffs premised on that concept ignored actual parallel flows and exacerbated congestion on parallel paths, which then required an inefficient set of rules to "unschedule" the grid, using physical curtailment rules (TLR, or Transmission Line Loading Relief) to keep actual flows within grid security limits. In contrast, Network Access Service looks at real flows and handles congestion by arranging and pricing the security-constrained, economic dispatch needed to accommodate each transaction.

While the NOPR describes Network Access Service as allowing a party to "move power" from generators to loads (e.g., NOPR ¶ 141), the SMD framework is not actually based on this misleading transportation imagery. Network Access Service is not about the right to "move" power from one point to another.

NAS can be interpreted as the right to use the grid and receive an integrated set of network coordination services from an Independent Transmission Provider that assures both open access and reliable grid operations. More precisely, NAS can be understood as the right to use the grid to inject (or sell) power at any location, and/or withdraw (or buy) power from any location, to have these actions accommodated by a bid-based security constrained economic dispatch, and to be settled at prices defined by LMP. "Settled" means that injections (or sales) are credited, and withdrawals (or purchases) are debited, at their respective locational prices, which ensures a consistent pricing mechanism for spot and bilateral transactions. All parties receive essential dispatch (balancing and congestion management) and ancillary services, while facing charges (or payments) based on the marginal costs (benefits) that their respective uses impose on the grid.[21]

Under NAS, transmission schedules are accommodated through the ITP's security-constrained, economic dispatch, with usage charges defined by LMP differences at source and sink. In that sense, SMD with NAS can be interpreted to redefine bilateral transactions, not as efforts to physically move power from point A to point B but instead as the net financial effect of injecting (or selling) energy at one location and withdrawing (or buying) energy from another location. From this perspective, bilaterals can be understood as financial contracts between buying and selling parties, rather than unrealistic physical commands placed on the flows across a network.

The NOPR's discussion of "scheduling" attempts to explain this but sometimes resorts to the familiar but inaccurate physical paradigm of Order No. 888. For example, the NOPR (¶144) says,

> "Thus, Network Access Service, coupled with Congestion Revenue Rights for the desired points, provides the customers with certainty with respect to delivery and price, comparable to the existing pro forma firm service."

We interpret this to mean that under Network Access Service, "certainty with respect to delivery" will occur because the ITP will provide a bid-based, security-constrained, economic dispatch, not because the ITP will "deliver" a specific customer's generated energy to the customer's loads. The ITP will then (1) use the dispatch to ensure all loads are met; (2) arrange the dispatch to resolve congestion as needed to accommodate any transaction willing to pay

21 Some ancillary services, such as reactive support, may not be included in marginal cost calculations; the cost can be recovered in an uplift charge.

congestion redispatch costs; and (3) charge for this service based on LMP prices consistent with this dispatch.

Similarly, according to the NOPR, a "customer would acquire Congestion Revenue Rights to assure price and delivery certainty for its transactions" (NOPR ¶149). While CRRs do allow for price certainty, it is the ITP's dispatch, not the ownership of CRRs, nor even a customer's "scheduling" generation to meet load, that ensures that loads are met with generation in real time.

B. A Transition from Existing Transmission Services to Network Access Service Will Be Necessary.

The NOPR properly recognizes that there are a number of transition issues in moving to the new Network Access Service. We comment here on three issues of particular interest.

1. There will be a transitional need for some point-to-point service.

The NOPR appears to recognize that point-to-point service will still be required for some transition period to handle schedules between ITPs. NOPR ¶110. This may be essential even between neighboring ITPs under SMD, because their respective dispatches will not initially be coordinated.

In the absence of fully coordinated dispatches across inter-ITP boundaries, each ITP will arrange its own security-constrained economic dispatch using the bids it receives. As long as there are separate bid-based dispatches, each ITP will generate its own set of spot market LMP prices, so the prices in each region will not necessarily be consistent with the prices in the neighboring region. Without a consistent set of prices across the regions, a consistent, unified set of inter-ITP CRRs cannot be defined. Further, without an inter-regional dispatch, the interties between neighboring systems must be scheduled in advance (typically an hour or so), at intervals that are longer than the 5-minute dispatch and spot market intervals anticipated by the SMD. For these reasons, something like existing point-to-point transmission service , as well as some pre-scheduling mechanism, will still be needed for inter-ITP transactions.

Eventually, it will be possible for neighboring ITPs to coordinate their dispatches so as to achieve a unified inter-regional dispatch with consistent prices that can support inter-regional CRRs. Initial forms of this have been developed for PJM-PJM West and may be developed further as Eastern ISOs and ITPs seek to coordinate their dispatches and associated spot markets. In the meantime, the Commission should allow ITPs to retain point-to-point service to accommodate inter-ITP transactions.

Finally, as discussed further below, the charges for point-to-point services may be important in dealing with seams issues between ITPs or for entities that are not served by any ITP.

2. Existing transmission contracts should either be converted to NAS or accommodated under NAS by the contracting transmission owners.

The Commission proposes to allow those parties with pre-Order No. 888 transmission contracts to convert to the new Network Access Service. This conversion would be done in conjunction with an allocation of CRRs or ARRs, in an effort to place each party in a commercial position more or less equivalent to what it had under the existing agreements.[22] However, the NOPR recognizes that equivalent conversion may not be possible for all contracts and proposes instead that existing contracts be honored by the transmission owner, which would support the contracts by taking service under the Network Access Service pro forma tariff.

NOPR ¶370. The transmission owner would then be responsible for meeting its contractual obligations to the contract customer. For example, it could be responsible for scheduling all transactions under those contracts but doing so under the rules for NAS. NOPR ¶371. This would allow all scheduling to be done under common rules, but it would also mean, for example, that transmission owners would be responsible for paying any congestion-related usage charges associated with those schedules implemented under the existing contracts. Any allocation of CRRs would therefore go to the transmission owner.[23] NOPR ¶374

We believe this is a reasonable approach, because it encourages conversion to the new system, provides mechanisms to protect the owner's revenue requirements and allows consistent scheduling practices during the transition. The alternative has been to allow those with existing transmission contracts to function under the contract provisions, even though these are often inconsistent with the market rules that apply to other transactions. For example, parties may have physical scheduling rights that require the ITP to physically reserve capacity on the system even if the contract party does not intend to schedule any transactions under the contract. This can lead to "phantom" congestion with increased usage charges or preclude other users from gaining access. Or it may encourage other parties to wait until real time to schedule their transactions with the expectation that large amounts of unused transmission capacity will become available at the last hour. In these cases, it would be preferable to require the transmission owner to arrange any schedules under the contract within the common scheduling rules of the ITP. The owner would pay any congestion-related usage charges.[24]

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22 Equivalent CRRs may sometimes need to be "options" rather than "obligations" to handle cases in which the contracting party does not have an obligation to either schedule or pay congestion charges.

23 A transmission owner would also have the right to file pursuant to Section 205 of the Federal Power Act in the event that these arrangements were insufficient to meet its revenue requirements.

24 We do not think it necessary for the Commission to disturb conversion agreements already reached in PJM and New York.

3. The Commission should reconsider its proposal for an interim tariff. A fair transition to NAS cannot occur without the essential pricing and dispatch components of SMD.

The NOPR proposes that "the transmission component of bundled retail service must be taken under an open access transmission tariff" in order to eliminate discrimination in favor of a transmission owner's bundled retail customers. NOPR ¶¶117-118. The elements of SMD will eventually eliminate this discrimination, but in the interim, the Commission proposes to require that bundled retail load be placed under the existing *pro forma* tariff. NOPR, Appendix A. Bundled retail customers would then be served by the transmission provider using Order No. 888's network integration service.

We are not convinced the interim tariff is worthwhile. Comparable treatment between various customers is not possible without comparable pricing of the necessary grid coordination services, including the dispatch that provides balancing and congestion management. Comparable pricing cannot occur in the absence of open, bid-based spot markets priced at LMP.

The NOPR proposes that service to native load customers under the interim tariff be comparable to other network customers when dealing with congestion, curtailment and other issues. In the event of redispatch to manage congestion, an occurrence that would be common, there would be no LMP pricing, and uplift costs for redispatch would be allocated to all customers on the basis of load ratio shares. The NOPR does not define how prices for imbalances would be determined, but this framework appears to be a form of non-locational, uniform pricing for congestion and imbalances similar to that used unsuccessfully by PJM prior to implementing LMP. In a fully regulated system, the absence of choice might render these inefficient pricing mechanisms less harmful. However, there could be problems with the interim tariff in regions that allow some degree of competition and retail choice. We are not convinced this represents an improvement over existing conditions, notwithstanding the Commission's desire to eliminate current preferential treatment. It is not clear what benefits would accrue to a region that was forced to provide "comparable" service under the existing *pro forma* tariff but had no means for defining comparable pricing for the essential services that support transmission usage.

Again we emphasize that the highest priority should be to create the open real-time spot market using the SMD framework of a bid-based, security-constrained, economic dispatch with locational prices. Since some balancing mechanism with associated pricing must be put in place, it would be best to move immediately to embrace this core of the SMD proposal. It is not that hard to take this step, and as experience has shown, failure to have a consistent spot market creates many new problems and provides no real benefits.

C. The Commission Proposals for Recovering Transmission Revenue Requirements Should Support the Competitive Market Structure of SMD.

The NOPR proposes that "transmission owners recover embedded costs through an access charge assessed mainly to load-serving entities, based on their respective shares of the system's peak load." NOPR ¶169. The access charge would be assessed primarily on loads, not generators. In addition, "through" and "out" transactions would not pay access charges, to avoid rate "pancaking." In RTOs combining multiple transmission systems, internal pancaking would be avoided through a license place approach. NOPR ¶170. We agree with these basic approaches, subject to some caveats.

A license plate approach for access charges makes sense as a way to avoid both intra-RTO and inter-RTO rate pancaking, is consistent with the core elements of the SMD, and is consistent with the proposed long-run policy for transmission investment; it need not be limited just to a transition period. Further, while some regions may agree to transition to postage stamp access charges, we believe requiring postage stamp rates would be a mistake. License plate access charges can eliminate pancaking of rates for transactions, and there is no reason that access charges be the same everywhere. To the contrary, under the postage stamp approach, equalizing access charges for existing assets would create cost-shift issues where none currently exist, while equalizing access charges going forward would directly contradict the proposed policy for transmission investment, which seeks to charge beneficiaries for the investment costs of future upgrades, while awarding to those who pay the embedded costs the incremental CRRs made possible by the upgrades.

1. Applying access charges to exports is probably needed as an interim measure.

By applying access charges primarily to loads, the Commission's proposal would discontinue the practice of applying an access charge to exports. We agree that access charges on exports can eventually be eliminated on inter-ITP transactions. However, it may be necessary to retain such charges for exports to entities that are not participants in any ISO/ITP. Once the rules are clearer regarding the treatment of non-participants, export charges can be reduced (as in PJM) and gradually phased out.

2. The Commission should avoid prescribing complex mechanisms for reallocating embedded costs that were previously recovered from "out" and "through" transactions.

The NOPR assumes that some transition mechanism will be needed to mitigate the shift in embedded cost responsibility once access charges are recovered primarily from loads and no longer recovered from "through" and "out" (exports) transactions. NOPR ¶¶179-189. This is correct. However, it is not clear that either of the NOPR's alternative proposals would be appropriate or would need to be standardized. The core features of the SMD depend only on the use of some allocation method that does not counteract the incentives for operation and investment. The particular allocation rule is not that important, and there could be regional variation in this matter. Neighboring RTOs should be free to develop mechanisms to reallocate embedded cost responsibility if they find it helpful in RTO formation. But requiring a particular agreement as a condition of RTO formation could be counterproductive and delay new RTOs.

Further, it is not clear that every region will find the net effect of eliminating "through" and "out" charges to be detrimental, once SMD is in effect. While there may be some change in the access charges paid by local loads, these will be offset by other benefits. For example, the elimination of access charge pancaking and the introduction of Network Access Service will expand open access and eliminate discrimination, so both exporting and importing regions should see benefits in more efficient prices and better access to regional markets.

3. CRRs should be allocated to point-to-point customers that continue to contribute to embedded costs.

The Commission seeks comments on whether existing point-to-point customers who currently pay access charges as a contribution to embedded costs should receive an allocation of CRRs. Under the NOPR, these customers would not contribute to embedded costs, which would be paid primarily by loads. The Commission presents two options for handling this situation, but we do not see them as mutually exclusive. As discussed above, a workable principle for allocating CRRs is that those who contribute to the embedded costs of the system should receive an allocation of CRRs (or ARRs). NOPR ¶171. Under this principle, it would be appropriate to allocate CRRs to those point-to-point customers who continue to contribute to embedded costs.

If a customer elected to discontinue contributing to embedded costs under the new tariff, it should not receive an allocation of CRRs.

4. Proposals for socializing grid investment costs should be avoided to the extent practical.

The Commission expresses concerns about what it perceives as inadequate investment in transmission to keep pace with load growth and the increase in generation investments and inter-regional trading. It attributes this concern to the difficulties of siting new transmission and the problems that arise when transmission upgrades that benefit one region, such as by relieving congestion between lower-cost generation and loads, must be made in another region that receives few, if any, benefits. Given these concerns, an important question is whether rolled in pricing or some other approach should be favored to encourage adequate grid investments. Under "rolled in" pricing for network upgrades, all users would pay a share of the upgrade costs, even for upgrades required for new generator interconnections to allow the generator to access the regional market. NOPR ¶¶191-194.

In general, we view these approaches in both the SMD NOPR and the proposed Generator Interconnection rules as both unnecessary and inconsistent with the core elements of the SMD. Under SMD, efficient spot market prices and associated usage charges reflect the locational effects of congestion and losses. LMP-based charges provide incentives for both generator interconnections and network upgrades. While siting issues and local concerns are present in any event and must be addressed, the core problem until now in non-LMP regions has been the absence of appropriate price incentives, a flaw that the SMD with locational marginal pricing will largely correct.

Complementing the incentive properties of LMP, the SMD would require ITPs/RTOs to award to those who invest in transmission upgrades incremental CRRs made possible by the upgrades. The LMP incentives and the award of property rights that reflect the value of the investments should provide the necessary support for market-driven investments in transmission upgrades that reduce congestion for the benefit of those sponsoring the investments. Once these mechanisms are in place, merchant projects driven by participant funding should occur – just as they are occurring in the Eastern LMP-based markets – to the extent there are no market failures. Only where there are market failures, and the regulator determines that, given the LMP incentives, an upgrade is economically justified, should regulators look to rate-based projects. In that event, we agree with the Commission that upgrade costs should be assigned to beneficiaries to the extent they can be identified, and if not, only then to all users on a rolled-in basis.

The Commission also proposes to require that investments for facilities at a certain voltage level, such as 138 kV and above, be rolled into rates on a region-wide basis, while allocating costs between regions based on an analysis of regional benefits. This approach would apparently apply only where there is no independent regional planning authority to approve participant funded upgrades. NOPR ¶200. The benefits analysis should help deal with the problem that regions that do not benefit from an upgrade have to bear both the siting and the costs of an upgrade that mostly benefits another region.

5. Access charges to recover embedded costs should be designed to avoid distorting the incentives for efficient market operations and investment.

In the presence of economies of scale, efficient prices applied without discrimination would not meet the total revenue requirement. Additional revenue must be obtained, and access charges provide an alternative that is consistent with the SMD design. The basic objective of the charges for embedded costs is to recover the needed revenue with the minimum of distortion of operating and investment decisions.[25]

There is no perfect solution for this problem. Regional flexibility could be allowed with the criterion that the rule should maintain as much as possible a disconnect between the access charge allocation and the decision about the choices in real-time dispatch.

D. The SMD Answers the Question of the Role of Independent Transmission Companies within the ITP Structure.

The Commission seeks comments on the functions that an Independent Transmission Company (ITC) should perform under Standard Market Design and asks whether an ITC could qualify as an Independent Transmission Provider. NOPR ¶¶132-135. We believe that an understanding of the core features of the SMD and how they relate to the provision of Network Access Service answers the question of the role of ITCs.

Under SMD, a single, consistent form of transmission service – NAS – would be provided on a non-discriminatory basis by the same entity that administers the day-ahead and real-time spot markets. These ITP-coordinated markets would be based on the ITP's bid-based, security-constrained economic dispatch, which would include economic "redispatch" to manage congestion and accommodate all transmission schedules for those willing to pay the LMP-based usage charges. The NOPR thus makes clear that the provision of open, non-discriminatory transmission service would be the automatic result of the ITP's necessary coordination of the dispatch and the associated LMP-based spot markets.

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25 For a discussion of the theory, see Transpower, "Confirmed Pricing Methodology; Final Design Principles," New Zealand, March 29, 2002, pp. 17-27. Available at: (http://www.ksg.harvard.edu/hepg/Standard_Mkt_dsgn/Transpower_design_prin_3-29-02.pdf)

Given this framework, there could only be one ITP for a given region. The provision of transmission, the accommodation of transmission schedules, and the operation of the spot markets would occur through one closely integrated set of functions coordinated with other interconnected ITPs. There could be no meaningful separation of these functions within a region that would be consistent with SMD, LMP-based spot markets and NAS. "Slicing and dicing" of these functions would be incompatible with the core concepts of SMD, and all attempts to separate these functions have demonstrated the sometimes severe problems of the separation fallacy.

The implication for ITCs is that they would essentially be in the same position as any other transmission owner within an RTO/ITP operating under the SMD. Like any transmission owner, an ITC would maintain the facilities it owned and operate those facilities pursuant to the operational instructions of the ITP. An ITC would be subject to the same requirements as any other owner with respect to coordinating grid maintenance activities and planning upgrades. There would be no need or justification for separate scheduling mechanisms for the ITC's portion of the ITP-controlled grid; indeed, separate or "local" mechanisms could be disruptive to the ITP's regional management of the grid and would result in inconsistent, balkanized pricing for transmission and balancing. This would create anew a fundamental problem for which the SMD is offered as a solution.

The same would be true for congestion management. An ITC could not manage congestion independently from the ITP's necessary operation of a regional, security-constrained, economic dispatch and associated spot markets. To the extent that an ITC could fashion and offer congestion management services to the ITP, based on grid operational actions, such offers would have to be treated by the ITP on the same basis as similar offers from any other transmission owner and then evaluated impartially by the ITP against generation bids for redispatch. No owner would be allowed unilaterally to implement its solutions. Under SMD, all congestion management would be coordinated by the ITP through its security-constrained, economic dispatch. Nor could the ITC (or any other transmission owner) control a separate dispatch for its region without creating a separate market and additional "seams" between the ITC (or owner's) boundaries and the rest of the ITP-controlled grid.

Hence, as long as an ITC were formed within the boundaries of an RTO/ITP, there does not appear to be any ITP function as defined in the SMD that could or should be delegated to an ITC, nor is there any reason to treat an ITC any differently than any other transmission owner. These principles would then allow the formation of ITCs to be based on more relevant business factors that would affect financial viability of an independent transmission business, issues that properly should be divorced from the question of ITP functions. Separating the formation of ITCs from the question of ITP/SMD functions might then facilitate ITC formation, while simplifying the Commission's consideration of ITCs. Issues of the ITC's independence and governance would no longer be a Commission concern. Furthermore, this separation of ITPs and ITCs would enhance the ability of ITCs to implement planned transmission expansion, because the ITC could cite the need as approved by the arm's length decisions of the separate ITP.

For these reasons, the Commission's efforts to carve out an acceptable set of the RTO/ITP core functions for an ITC to perform appear misplaced. If they ever had a place as a transitional feature before an RTO/ITP becomes operational, that justification would end once an RTO/ITP were functioning under SMD, an event that would require the Commission to revisit the allocation of functions it previously authorized.[26] As ITC's emerge, RTO/ITPs will need to

[26] See, e.g., *TRANSLink Transmission Co. LLC, et al.*, FERC ¶61,106 (2002), discussed in the SMD NOPR at ¶ 133.

agree on an appropriate role for ITCs that does not undermine the SMD. While these arrangements may vary by region, the Commission and RTOs should be cautious in attempting to carve out any role for an ITC that might adversely impact the essential integration of the SMD core functions.

A more difficult question is whether the ITC could be the ITP for the entire ITP/RTO-controlled grid. Here the question turns on the concerns over having a transmission owner in charge of running the bid-based spot markets and associated security-constrained, economic dispatch, as well as other core functions. A particular concern would be whether the LMP-based investment incentives for transmission upgrades would unavoidably create conflicts for a transmission owner if it were allowed to operate the LMP-based spot markets that manage congestion and define the value of transmission usage. These markets would define the market value of transmission expansions relative to other investment options.

While an ITC would presumably be independent of generation interests, it would have its own commercial interests in pursuing market-based investments in transmission and receiving the incremental CRRs (or ARRs) made possible by grid expansions. It might be competing with other merchant transmission companies for the same investment opportunities. And it would be competing against generation and demand-side investments to capture the value of reducing congestion as defined by locational price differences. The Commission might then need to adjudicate disputes over bias in executing markets, system control, misuse of confidential information, and charges of creating barriers to non-ITC investments, such as through handling of generation interconnection requests or treatment of merchant-driven transmission investments in the regional planning process. In practice, any ITC would have to set up rules and procedures to separate and isolate ITP activities within its organization. There would need to be a least a conflict wall, or more substantial separation, to ensure *de facto* if not *de jure* independence for the ITP functions. Further, the Commission would then be placed in a position of exercising constant oversight to ensure compliance with open access and non-discrimination with respect to the ITP's treatment of other market participants. These concerns suggest that it might not be worth the effort that would be needed to oversee the actions of ITCs functioning as ITPs.

There are certainly models of transmission owner-operators in regions with markets, and indeed the owner-operator in New Zealand operates an LMP-based market with many of the features of the SMD. Transpower, the New Zealand owner-operator, is a government monopoly that has had a statutory mandate to operate markets impartially and in the public interest.[27] Other examples of an owner-operator market include the United Kingdom (UK), where the market design relies on a monopoly owner-operator for the entire grid. The UK market does not use locational pricing and has no means to encourage multiple transmission companies or accommodate merchant-driven transmission investments. In that regime, transmission investments are done exclusively by National Grid, the owner-operator, and rely on performance-based incentives defined by the UK regulators. This system is incompatible with, and inferior to, the Commission's SMD framework in supporting the principles of open access and non-discrimination.

Hence, although it is possible in principle to have the employees of the ITP share overhead services and senior management with an ITC, the practical requirements of the market would dictate effective separation of the functions of the ITP and decidedly prohibit an incentive system where the ITC made the decision about the tradeoff between market rules and transmission investment. In the context of the United States without a monopoly ITC across the entire grid and with the principles of open access and non-discrimination, the savings in overhead costs of the ITP seem small when compared with the oversight costs for FERC in ensuring the necessary independence and equal treatment of all market participants. Independent transmission companies can play a major role under the SMD and are completely compatible with the Commission's intent and design, but embedding the ITP functions within an ITC probably creates more costs than benefits.

IV. ISSUES RELATING TO THE REAL-TIME MARKET

A. Under SMD, Each ITP's Priority Should Be to Design and Implement an Efficient Real-Time Market Founded on a Bid-Based, Security-Constrained Economic Dispatch with Locational Pricing.

1. Establishing an efficient real-time spot market using consistent nodal prices should receive priority over day-ahead markets and other enhancements.

In describing the SMD requirements for the ITP spot markets, the NOPR could be read to focus first on the day-ahead market over the real-time market. NOPR ¶269. We urge the Commission to refocus on the real-time market as the essential feature of the SMD.

Markets that employ consistent day-ahead and real-time spot markets founded on a bid-based, security-constrained economic dispatch offer a proven, workable design. However, whereas a consistent day-ahead market is an enhancement to the basic market structure, the essential market feature is an efficient real-time spot market priced at LMP. The incentives in this market will determine in large part the behavior in forward markets. A well designed

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[27] This formal mandate may change as part of a current review of governance structures in the New Zealand electricity market. However, Transpower will continue as a state-owned enterprise taking its policy direction from the government.

forward market cannot overcome a badly designed real-time market. And as demonstrated in PJM, a well-designed real-time market deals with the most egregious problems and prepares the way for other market developments. In regions that are just beginning the development of coordinated markets and must make choices about which market features to develop and implement first, and which to phase in later, the Commission should leave no doubt that the real-time spot market and its associated dispatch with locational pricing have first priority.

An efficient real-time spot market is essential to the market structure. It is this element that forges the critical linkage between what the system operators must do to ensure reliable operations, the incentives market participants face, and the actions participants take in response to those incentives and their own commercial interests. While a market can be designed to function reasonably well without a day-ahead market, an electricity market cannot function well without an efficient real-time market. Once this is in place, the market can be enhanced, and reliable operations made easier, by various day-ahead elements, including a full two-settlement system, possible day-ahead optimization of reserves and energy, and a forward unit commitment process.

2. The real-time market should not be limited to "incremental" and "decremental" bids from day-ahead bilateral schedules.

The NOPR could be read to restrict the real-time dispatch to "inc" and "dec" bids relative to balanced day-ahead schedules. If the NOPR intends this interpretation, we do not believe this restriction is either necessary or appropriate. It is possible that this limited approach arises from the NOPR's initial focus on the day-ahead market and day-ahead "schedules." However, this limitation should be avoided for several reasons.

First, some regions may not initially have a day-ahead market with binding financial commitments (i.e., a fully two-settlement system). Some regions may instead begin their markets with only the real-time spot market. The closer we get to real-time, the more important it will be to give the operator flexibility and to avoid unnecessary and inefficient restrictions on the dispatch.

Second, the NOPR appears to assume that most bilateral transactions must be "scheduled" in advance with the ITP. However, as we explain above, for purposes of arranging the security-constrained economic dispatch, there is no need for parties that choose to contract bilaterally to schedule in a manner that explicitly links the supplier's schedule with the buyer's schedule. All that is required is that the ITP know each supplier's location, bids or intentions and each buyer's expected load; the bilateral contract between the supplier and buyer is relevant only for settlement purposes. If the SMD were to restrict the real-time dispatch to "inc" and "dec" adjustments to physical bilateral schedules, the SMD would inadvertently overturn the flexible and very straightforward manner in which both New York and PJM currently handle transaction settlements. This might be handled by defining zero schedules as balanced and acceptable, with associated "incs" and "decs," but this approach would more likely confuse than clarify.

Third, restricting the real-time dispatch to the incs and decs from day-ahead schedules implies that the day-ahead market is mandatory – every supplier and every load must participate in that market or be excluded from the real-time market. However, the successful day-ahead markets in PJM and NY are essentially voluntary. Parties may choose to participate or not, and wait for the real-time market. This is not just a matter of allowing commercial flexibility; it is a practical necessity. It would be difficult to compel parties to participate in any forward market and the enforcement effort would constantly be involved in disputes over deliberate "under-scheduling" in the day-ahead market. This was the experience in California.

Fourth, the limitation to incs and decs from day-ahead schedules implies that all generation and all loads are contracted in advance. If this were the rule, there would be no market opportunities for generators with additional, uncontracted capacity to offer that capacity to the ITP's spot markets.

Parties should be free to submit, and the ITP required to use, generator supply offer curves and load/demand bid curves, irrespective of whether they schedule/engage in bilateral transactions or participate in the day-ahead market. Otherwise, the dispatch will not be efficient and the balancing/spot market costs will be needlessly higher.

Once the ITP's spot markets are open to all bidders, the ITP should use all submitted offers and bids to arrange its security-constrained economic dispatch. The alternative rule would exclude those offers/bids from parties that were not fully contracted, thus discriminating between parties while impairing dispatch efficiency and reliability.

B. Rules for Defining LMP Prices in the Real-Time Market Should Focus on Reflecting the Actual Dispatch and Encouraging Parties to Follow Dispatch Instructions.

1. The SMD should avoid being overly prescriptive in requiring *ex post* versus *ex ante* pricing or in specifying the details of *ex post* pricing.

The NOPR appears to favor an *ex post* pricing approach over an *ex ante* approach, primarily to encourage generators to operate in a manner consistent with their bids and the ITP's dispatch instructions. There are some advantages in an *ex post* approach. PJM notes, for example, that it appears to reduce errors in real-time prices. There is no clear choice, and ITPs should be allowed flexibility to use either method, particularly during a transition when existing software limitations may dictate the answer.

There is less here than meets the eye in the literal definition of the two pricing methodologies. With prices posted rapidly, market participants can respond even if the prices are lagged by a few minutes. Hence, real-time systems would tend to have some of both features. However, there may be more than meets the eye in the connection with the treatment of dynamic systems. The constant requirement for management of the dispatch over the hour and the day creates conditions that may be hard to capture precisely in a simple and relatively static price calculation. The SMD proposal here may require some regional diversity in the details in the management of ramp, start-up, end-of-hour effects and other very short-term scheduling phenomena. The basic principles of LMP still apply, but the implementation may accommodate small differences across regions.

We agree that the spot market LMP prices should be consistent with the dispatch and grid conditions, and with the parties' offer and bid curves, so that the prices will tend to encourage the parties to follow the ITPs instructions for an efficient, reliable dispatch. However, the Commission should be aware that there is no "standard" *ex post* pricing approach; the *ex post* method used by PJM differs slightly from the *ex post* method that the NY ISO is developing, and we have no strong policy reason for standardizing these details.

2. Each region should have the flexibility to use or not use penalties for uninstructed deviations from dispatch instructions, depending on regional considerations.

The NOPR asks for comments on whether there should be charges for uninstructed deviations. NOPR ¶316. Such penalties may or may not be needed, depending on how LMP prices are defined and how important it is to the ITP to have generators closely follow dispatch instructions. For example, in densely populated load centers such as New York City, the system may be more sensitive to relatively minor deviations from dispatch instructions than would be the case in other areas. These are matters that the Commission should leave to each ITP to determine on a regional basis.

Similarly, the Commission should leave to each region the development of incentives or penalties designed to reflect the costs of uninstructed deviations on other ancillary services, such as regulation. There is no obviously correct approach that warrants standardization at this time.

3. "Lumpy" resources should be eligible to set prices, but special rules may be required to accommodate imports.

The NOPR appears to recommend that "lumpy" resources, including imports, be allowed to set real-time spot prices. We agree that where a resource is economic over the ITP's dispatch horizon, and is the marginal resource, it should be allowed to set the market-clearing price. However, as the Commission knows, the existence of lumpy resources means that some approximation must be allowed for marginal cost calculations. There is no single best rule for how this is to be done, and there may be good reasons for using slightly different implementations in different regions. In addition, the rules here may interact with the policies for market power mitigation.

For example, imports may be treated differently because intertie schedules must be defined in advance and fixed (e.g., hourly). For these and other reasons, imports cannot easily participate in five-minute markets and may not be able to set five-minute market prices without financial risks. Within the broad framework of the SMD, there could be different regional approaches, at least as part of a transition period, with special care taken to avoid gaming issues.

C. Specifying a Five-Minute Dispatch and Market Settlement Interval Is a Worthwhile Goal for the End-State SMD, But Regional Flexibility Should Be Allowed During a Transition.

The NOPR anticipates that all ITPs will eventually implement five-minute (or other sub-hourly) settlements consistent with their five-minute dispatch intervals. NOPR ¶ 310. This is currently the case in New York but not in PJM, which integrates five-minute prices into an hourly price for settlements. New England ISO and Midwest ISO are proposing to implement five-minute dispatches and markets; California currently uses a ten-minute dispatch and market intervals.

In the longer term, consistent dispatch and market settlement intervals will be helpful in facilitating inter-regional coordination of the dispatches and spot markets between neighboring RTOs. In addition, a five-minute interval appears to be the emerging standard and is worthwhile because it encourages generators to follow more timely dispatch instructions. However, existing ISOs with other intervals should have a reasonable transition to move to this standard because of the costs and time required to change existing dispatch and settlement software. This transition may not be as important as efforts to expand the scope of existing markets, and different regions may have different priorities for this feature. Subject to Commission approval, ISOs/ITPs should have flexibility to set priorities on alternative market improvements as they expand market functionality.

V. ISSUES RELATING TO THE DAY-AHEAD MARKET

A. The SMD NOPR Correctly Notes the Importance of the ITP Using Operating and Market Tools Consistent with Those It Uses in the Real-Time Market and Dispatch.

We interpret the NOPR as requiring that the day-ahead operating and market tools and pricing rules be consistent with those used in the real-time market. NOPR ¶ 269. We agree with this principle. The advantage of this approach is that it will tend to ensure that schedules arranged in the forward market will be feasible and not require curtailment or redispatch in real time. Internal consistency will also minimize the potential for gaming, while still allowing efficient arbitrage between the day-ahead and real-time markets. As we know from the experience in California, it is important to remove any artificial distinctions between the day-ahead and real-time markets. To the extent possible, anything that is feasible in one market should be feasible in the other. The grid description and market rules should be the same. Otherwise, the discrepancies either prevent efficient markets or create opportunities and incentives for gaming that reduce reliability and increase costs.

The typical example in California was to schedule day-ahead transaction using a simplified network model that created infeasible schedules. This created opportunities to overschedule the system at little cost and then be paid later to undo the transaction. The California ISO subsequently summarized the experience:

> Upon reexamination of the [Congestion Management Reform] proposal we find that some of the crucial assumptions underlying the [Locational Pricing Areas] concept break down.… [I]n reality, the "simplicity" of the zonal system only appears so because the complexity is assumed away, allowing market participants to ignore it in scheduling while the CAISO must manage it through real time adjustments and periodic modifications to the rules to mitigate novel gaming strategies as they arrive. . . [I]t will be far simpler, and more transparent, to design

> forward [congestion management] procedures to be as consistent as possible with the real-time operating needs of the grid.[28]

The lesson from California has been reinforced by the experience in markets in PJM and NY where the consistent day-ahead and real-time market designs have reinforced reliable and efficient operation.

B. The NOPR Recommends that Day-Ahead Markets for Operating Reserves Be Coordinated and Simultaneously Optimized with Energy Markets. This Feature Can Be Part of the SMD End State, But ITPs Should Be Given Flexibility in Deciding the Priority to Give This Enhancement.

The NOPR proposes that each ITP operate both day-ahead and real-time markets for certain ancillary services, including regulation and operating reserves. It further proposes that these markets be co-optimized with the ITP's day-ahead and real-time energy spot markets. NOPR ¶¶290 and 323. These are worthwhile proposals that should be included in any end-state market design. However, the day-ahead market involves some special features that arise in unit commitment. Furthermore, the use of a companion reliability commitment to protect the ability to meet real-time load means that there are more complex interactions to address in arranging the dispatch and setting consistent prices.[29] The Commission should exercise caution in being overly prescriptive in the SMD because of the complexity involved in these concepts and the significant potential for unintended consequences if the details are not properly understood and reflected in software design.

Ideally, energy and operating reserve markets should be co-optimized so that the ITP selects the most economic combination of resources to satisfy the demands for both energy and

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[28] CAISO proposal, "Market Design 2002 Project: Preliminary Draft Comprehensive Design Proposal," January 8, 2002, pp. 13-14.

reserves. The ITP would then define the market-clearing prices for each service so as to ensure that each service provider would be no worse off providing the service it was asked to provide (e.g., spinning reserve) than providing an alternative service (e.g., energy). This pricing approach thus includes the opportunity costs faced by the service providers, as reflected in their bids and thus lowers generators' bidding risks and encourages marginal cost bidding.

We believe the Commission understands the advantages of this approach over separate, sequential markets for energy, regulation and operating reserves.[30] For one thing, sequential markets effectively require strategic bidding because potential providers must guess the clearing prices that will apply in each market and adjust their separate bids accordingly. The increased risks of bidding incorrectly (or gaming) can easily lead to higher costs to the market.

The main remaining issue for the Commission is the priority and timing for achieving this long-term goal. For developing markets, the priority should be to work toward these enhancements in the real-time market first, because that is where getting the prices right will strengthen the real-time dispatch used to ensure reliable operations. In addition, the coordinated spot markets should be complemented by introduction of CRRs that allow market participants to hedge changes in congestion prices. Once the design principles are clearly defined to achieve this goal in the real-time market across the entire footprint of the ITP, there could be additional benefits in applying them also to the day-ahead market and a two-settlement system.

The details here interact with the problems of providing the required flexibility for real-time operations without creating unintended incentives to deviate from the dispatch in providing energy and ancillary services. Adding to the complexity is the manner in which the ITP defines

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29 Michael D. Cadwalader, Scott M. Harvey, and William W. Hogan, "Reliability, Scheduling Markets, and Electricity Pricing," Center for Business and Government, Harvard University, May 1998.

30 California ISO has had problems with the sequential approach; the co-optimized approach used in New York ISO has proven beneficial to market efficiency, especially during scarcity conditions.

its market-clearing prices. Consistent five-minute prices and settlement periods produce one result; hourly integrated prices based on five-minute dispatch produce another. Failing to account for these differences may then lead to unintended, uneconomic selections for service providers when the ITP attempts to co-optimize across markets.

The PJM and New York markets each contain enhanced features that generally move in the right direction. The designs are not identical, however, and each is on a somewhat different path toward the desired end state. Further enhancements are possible in the direction indicated, but they should not be imposed through SMD, nor should FERC attempt at this time to spell out a detailed blueprint for the ideal solution. Rather we urge the Commission to recognize the importance of first getting the real-time market and its prices right and consistently applied across the ITP or RTO footprint. With respect to the enhancements of a day-ahead market, the SMD should indicate the principles of its desired end state and allow each ITP/RTO the flexibility to move toward that end state in a way consistent with the different starting points and the priority each gives to the various market enhancements that present competing claims for the ITP's attention and funding.

C. <u>The End-State SMD Should Accommodate Virtual Bidding, Provided Certain Prerequisites Are Met.</u>

The Commission asks parties to comment on whether "virtual" bidding should be permitted in the SMD. NOPR ¶ 272. We believe virtual bidding can be a beneficial feature of any end-state market design, but there are important caveats.

Virtual bidding is expressly permitted in both the New York and PJM markets and is generally viewed by both participants and the ISOs as a market enhancement that allows efficient arbitrage of prices between the day-ahead and real-time markets. With virtual bidding, the prices tend to converge and the markets tend to be less volatile and more stable. However, there are essential features of these two markets that enable these beneficial outcomes, and the Commission should focus on securing these features before considering the abstract question of whether to allow virtual bidding.

First, in both markets there is a well-established, efficient and robust real time market, founded on a bid-based security-constrained economic dispatch with nodal (LMP) prices. Whatever the structure of the forward (day-ahead market), it is the real-time market and its spot prices that provide the target for arbitrage through virtual bidding. Second, both regions have taken care to ensure that the approach used to arrange the dispatch and determine the prices in the day-ahead market is consistent with the approach used in the real-time market. A robust, efficient real-time market and a consistent approach for the day-ahead market then provide the proper foundation for virtual bidding and efficient arbitrage.

Whatever the market design, parties will tend to exploit differences between the day-ahead and real-time markets. If there are inconsistencies between the markets or inefficiencies in either market, parties will seek to arbitrage any systematic differences that these flaws create. If explicit virtual bidding is allowed, parties will use that mechanism to exploit these differences. But even if explicit virtual bidding is not allowed, parties will still have incentives to exploit differences in day-ahead and real-time prices. Thus, even parties with actual resources and loads will engage in implicit virtual bidding, either by submitting bids or schedules they do not intend to follow or by submitting bids or schedules they intend to follow initially but cannot (or chose not to) follow in real time. In that sense, all bids and schedules in the day-ahead market can be understood to be "virtual," because they are essentially financial, whereas the real-time market is physical.

In a two-settlement system envisioned under SMD, there is no fundamental distinction between these "implicit" actions and "explicit" virtual bidding. Attempts by the ISO to prohibit implicit virtual or financial trading will force the market to deal with charges of misleading scheduling (called "underscheduling" and "overscheduling" in California), investigations of misconduct and potential penalties. As California's experience demonstrated, this is a no-win situation for both ISO and participants.

If the SMD takes care to ensure a robust, efficient real-time market and consistent approaches for the day-ahead markets, market rules can and should permit explicit virtual bidding in the day-ahead market. The ITP can then define rules for when to consider virtual bids and schedules in the day-ahead process and when to exclude them for the purpose of committing units to ensure reliability in the real-time market. Rules can require that virtual bids be flagged by the participants, allowing the ITP to remove them from the reliability commitment.

Moreover, once the proper foundation is laid, the presence of virtual bidding will make it unnecessary to standardize the rules for how the day-ahead market connects with the reliability commitment. For example, New York and PJM follow somewhat different rules with respect to the reliability commitment, with New York including the committed units in a final pass to determine day-ahead prices and PJM determining the day-ahead prices prior to the reliability commitment process. Either mechanism should be acceptable, and with virtual bidding in place, these differences do not need to be reconciled or standardized in SMD, because virtual bidding will tend to equalize the day-ahead prices between the two approaches. As long as the participants understand what the pricing and commitment rules are in the day-ahead market, they will adjust their virtual bids accordingly. That is, given the different commitment rules, virtual bids in New York will be slightly different from virtual bids in PJM, which will tend to make the two approaches produce similar day-ahead prices. Each set of participants will then use virtual bidding to arbitrage away differences with the respective real-time market, thus improving the performance of the system.

D. The NOPR Proposals for Optimizing Unit Commitment in the Day-Ahead Market Are Generally Reasonable.

The NOPR apparently anticipates both an initial security-constrained unit commitment process as part of the day-ahead market and a residual unit commitment process, after the "close" of the day-ahead market. These unit commitment processes can be useful in helping the ITP ensure real-time reliability and in reducing generator bidding risks while ensuring reliability and simplicity in providing supply to the market.

It appears that the NOPR's replacement reserves proposals (NOPR ¶ 299-301) and a "residual unit commitment" (e.g., as proposed by the California ISO) are describing similar processes and should be guided by the same principles.[31] The goal is to ensure that there will be sufficient units available in real time to meet the ITP's forecast of demand, even if there would not otherwise be enough units committed from the "voluntary" day-ahead market. Generators would be appropriately compensated for making their units available for this purpose.

The NOPR proposes to ensure that units committed by the ITP recover their no-load and start-up costs. That is, the ITP-committed units would be made whole after accounting for revenues received in the energy and operating reserve markets. This approach has proved to be workable in PJM and New York and reduces generator bidding risks.

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[31] Similarly, a reliability unit commitment process is analogous to the current California ISO practice of exempting units day-ahead from the must-run obligation. There appears to be no policy reason why the ISO should be prevented from transitioning from the one to the other.

The NOPR proposes that the reliability unit commitment optimization be based on minimizing commitment costs, as opposed to total production (including energy) costs. The NOPR approach, currently used in New York and PJM, is sound. An alternative rule in which the ITP included incremental energy costs in the reliability optimization would tend to encourage loads to rely on the ITP to serve them, while allocating the uplift costs of reduced LSE risks to all users. This could reduce any incentives LSEs have to acquire their resource needs in advance.

E. <u>The SMD NOPR Should Not Require that ITPs Allow Transactions to Specify Maximum Congestion Charges They Are Willing to Pay.</u>

The Commission proposes to require ITPs to allow parties to specify "the maximum transmission usage charge (reflecting the costs of congestion and marginal losses) at which the customer desires service." NOPR ¶ 258. While this concept of an "up to" congestion bid seems appealing, it presents at least two difficulties that should be addressed in the Commission's final order. First, although feasible in principle, implementation would require a change in dispatch software to incorporate a separate constraint for each such bid. With only a few such bids, there should be no technical difficulty, but if there were many such bids, then feasibility testing would be required. Second, there is a potential for gaming. In addition, it is possible to achieve the objectives through an existing bidding approach without these difficulties. The Commission should therefore not include this feature as a priority element of the SMD.

The problem arises because the ISO/ITP must focus on arranging a bid-based security-constrained economic dispatch with the objective function of maximizing the bid-based net benefits of supply and demand. This is a complex problem in itself, which ends with an economic dispatch solution and spot prices defined by the dispatch for each location. The "up to" congestion charge proposal would require that the ISO/ITP solve a different problem. Instead of just solving the dispatch function, the operator must now accommodate the "up to" bids in such a way that depends on the locational price outcomes of the dispatch.

Faced with these difficulties, both the PJM and New York ISOs limit the use of "up to" congestion bidding. In New York, this option is available only for wheel-through transactions, in which the ISO can assume that the external generator is not otherwise part of the dispatch for New York loads and that the external load does not have to be served by the New York ISO's dispatch. PJM extends "up to" bidding slightly by allowing it for wheel-throughs, imports and exports, but not for solely internal bilaterals. PJM also limits the "up to" bid to $25 per megawatt-hour. These restrictions are designed to avoid the difficulty of trying to arrange an economic dispatch while simultaneously accommodating "up to" bids that depend on the dispatch price outcomes. Both ISOs have limited the concept out of concerns for its broader workability and the potential for gaming.

Gaming is the second concern that the Commission should consider. Although we recognize the superficial appeal of "up to" bidding, on closer inspection it looks like a holdover from the old physical contract path scheduling model. In the context of the SMD, however, a superior alternative would be to bid independent "incs" and "decs" for load and generation, and this form of bidding is already available. It is an easy matter to construct examples where a competitive bidder would lose money under an "up to" bid compared to independent bidding of load and generation. Further, we have not been able to construct an example of any benefit from "up to" bidding for internal transactions. Our concern, then, is that the "up to" approach might create a mechanism to game congestion management to enhance market power in generation by way of economic withholding of transmission in the day-ahead market. Bilateral schedules without accompanying “incs” and “decs” might be used for a similar purpose, but with “up to” bids, this strategy could be made more effective. We can see an argument for bilateral schedules without any accompanying bids as a simple practice that avoids the cost of constructing bids. But once bids are introduced, this simplicity advantage no longer applies, and the absence of any theoretical argument in favor of “up to” bids over standard independent “inc” and “dec” bids suggests caution is warranted.

Because “up to” bidding might become a useful enhancement to the ITP spot markets, the Commission should allow ISO/ITPs to continue to develop workable solutions to the problems. However, “up to” bidding is not essential to the core design, is not yet workable for all transactions, appears inferior to other bids for internal transactions, and may be subject to gaming. We conclude that “up to” bidding should not be a priority or mandated feature of SMD.

VI. MARKET POWER MITIGATION

A. The Commission Has a Workable Framework for Market Power Mitigation and Recognizes the Need to Balance with the Need for Scarcity Pricing.

The Commission recognizes that “[e]ven with good market design rules, current supply and demand conditions make a market monitoring and market power mitigation plan necessary.” NOPR ¶ 13. The Commission’s analysis correctly highlights the two principal problems as a present lack of sufficient demand-side response and the existence of transmission constraints that can create small local pockets where there is an effective monopoly. The lack of sufficient demand-side response is both a serious problem during the transition to a workably competitive market and a target for policy improvement. The Commission includes expanded demand participation in the market as a priority with benefits that include mitigation of market power.

The existence of local pockets of effective monopoly presents an immediate problem and may persist indefinitely, requiring targeted local market power mitigation as part of the permanent standard market design.

There is no simple or ideal method to mitigate market power, and it is probably not possible to fully eliminate market power. The challenge is to develop practical mechanisms that acknowledge the complexities of the electric supply system, without significantly undermining the incentives signaled during times of scarcity. Every proposal, therefore, is a compromise that involves tradeoffs. The NOPR seeks a balanced system focused on approximating the outcome of a competitive market absent any structural defects. The Commission offers targeted mechanisms that attempt to distinguish between high prices due to scarcity and high prices caused by an exercise of market power.

The Commission emphasizes the use of *ex ante* measures that would preclude price and market outcomes reflecting a substantial exercise of market power. This is preferred to *ex post* measures that would require complicated and contentious mechanisms for retroactive price adjustments and refunds.

1. The use of bid caps, rather than price caps, is consistent with the core elements of SMD.

In addition to expanding demand participation in the market, an *ex ante* tool that attempts to approximate the outcome of a competitive market is the use of bid caps rather than price caps. Under the SMD, the price in the spot market would be determined through an interaction of all bids given the existing supply and demand conditions. A price cap that applies to the outcome of this process is well known to be difficult to implement and prone to creating inefficient outcomes and perverse incentives for investment. By contrast, a bid cap applied to those who could exercise market power targets the problem but does not carry with it the same difficulties of a price cap. A properly designed and implemented bid cap would only apply to the particular sellers when they have the ability to impact the market, and the cap would vary depending on the type of plant or conditions.

Although setting bid caps is not easy, it is much easier than trying to find the single market price cap that would apply to all facilities and conditions. Under the bid cap approach, sellers who have market power must offer their power with approved bids but the market price is determined through the usual spot market mechanism and applies to everyone. Hence, the bid cap mitigates market power without preventing true scarcity from determining the market price. For example, with even a little demand-side response, demand bids that might be much higher than the bid caps could and should set the market price. This price would apply to all supply, including the supply from sellers with market power, but these sellers would not be able to affect the market price in conditions of scarcity. The bid cap approach is targeted and consistent with the Commission's objective of mitigating market power while not precluding true scarcity pricing.

The principal means for dealing with local market power is the Commission's proposal to require the ITP to identify those locations and conditions where production from particular generators would be required and hence these sellers would have an effective monopoly. The Commission would have the ITP identify an appropriate bid cap for these sellers and couple this with a "must offer" requirement. This follows on the current practice with reliability must-run (RMR) generating units. Although the details matter, the Commission has outlined the basic criteria that reflect the goal of providing realistic bid caps that are very likely to be above the generator's direct plus opportunity costs, and well below the levels that would reflect substantial economic withholding. The basic principles are sound, consistent with the broader SMD framework, and can provide a workable mechanism for dealing with the targeted local market power problem.

2. A properly structured safety net bid cap to achieve a proxy for scarcity prices can be a transitional substitute for inadequate demand-side response.

For the broader problem of inadequate demand-side response throughout the market, the Commission proposes a safety net bid cap of something like $1000 per megawatt-hour (MWH) to be applied to all sources as a proxy for the absent price-responsive demand. The logic here is that where there is sufficient demand participation, the demand response would itself mitigate market power while allowing sufficiently high prices in times of true scarcity to provide proper signals for both operations and investment. But absent this demand response, there should be a limit on all bids that serves as a proxy for the missing demand bids.

The basic logic dictates that this safety net bid cap should be close to the price at which load would be prepared to voluntarily reduce if only the market institutions were in place to make this reduction possible. An attraction of this approach is in establishing a principled means of selecting the safety-net bid cap. In particular, the purpose of the safety-net bid cap is not simply to produce low prices in times of scarcity; rather it is intended to be a proxy for the scarcity price. Seen as this proxy for the true value of demand, the $1000 per MWH number may well be too low.[32] Part of the task for the Commission, therefore, will be to address the justification for any safety-net bid caps below this level and to consider a transition process that

[32] The scarcity response should reflect that cost of involuntary curtailments in energy or reduction in reliability that would occur in the presence of binding caps and the need for extraordinary action by the ITP. This suggests that the safety-net bid cap should be more than the marginal cost of curtailment, and closer to the average value of demand.

gradually increases the safety-net cap as we gain more experience with demand-side participation in the market.

The success of each of these two elements of the market power mitigation plan would depend on the details of implementation. In general, we see the Commission's discussion of the tradeoffs and the purposes of the policy as both well conceived and properly reflective of the requirements for developing a workably competitive market. The constant tension identified by the Commission is between the need to mitigate any substantial exercise of market power and the need to allow market forces to reflect true scarcity prices.

That the Commission intends to maintain the balance, simultaneously limiting abuse but protecting scarcity pricing, is especially evident in its discussion of hydropower, imports and exemptions. In the case of hydropower, the Commission recognizes the problem of estimating opportunity cost and the close interaction of energy pricing and reserve pricing. NOPR ¶ 422. Hence the Commission offers as one approach that hydropower be subject only to the safety-net energy bid cap as long as the units are in merit for providing reserves. This would imply that whenever hydropower was providing energy, the market prices for everyone would reflect opportunity costs or scarcity prices subject only to the safety net. As for imports, the Commission recognizes that imports should be allowed to set the market price as another means of including the price of true scarcity, subject only to the safety net. NOPR ¶ 413. Both features would provide important mechanisms for scarcity pricing to operate without allowing a substantial exercise of market power.

Finally the Commission proposes to exempt certain sellers, again subject to the safety net. NOPR ¶ 428. Such exemptions seem entirely appropriate for both the economic reason that some small entities could not reasonably be expected to exercise a substantial degree of market power and for the administrative reason of simplifying administration and enforcement. The exemptions would be important in another way that is consistent with the Commission's policy. Because even a small seller could reflect a true market scarcity situation, the exemptions could help discovery of a true market-clearing scarcity price that would be above various generator bid caps.

B. The Commission Should Focus on Well Designed Bid Cap and Safety Net Mechanisms Rather than Assume that a Resource Adequacy Requirement Will Easily Solve the Problem of Inadequate Investments.

Despite these features of the Commission's proposal, and the careful attempt to achieve balance in market power mitigation and scarcity pricing, the Commission expresses a concern that spot market prices may not set an adequate incentive for investment, partly because of the effect of the mitigation measures. NOPR ¶ 461. One ingredient of the Commission's response to this dilemma is the long-term resource adequacy requirement that is the third part of the Commission's proposed market power mitigation plan. As discussed below, this resource adequacy plan is problematic. It would be wise for the Commission to take care in implementing the other features of the market power mitigation plan, which are needed in the current markets, without relying on the success of a long-term resource adequacy proposal to counteract any problems created by the market power mitigation rules.

C. The Commission is Correct to Be Cautious About Imposing Automatic Mitigation Procedures, Which Can Become Overly Intrusive If Not Carefully Designed and Limited.

This perspective would be especially important in considering the details of implementation of the fourth part of the Commission's mitigation proposal to be triggered under certain market conditions. The Commission is not precise about the market conditions other than that they would be unanticipated. Here the call is for another type of backstop procedure that protects the market from conditions that are hard to predict but would be ripe for exploitation of market power. Although the Commission would not require an ITP to adopt this measure, the proposal is to apply something like the Automatic Mitigation Procedure (AMP) used in New York and adopted recently for the California ISO. The basic idea of an AMP when triggered is to repeat the logic of the local market power mitigation plan with targeted bid caps but to expand this system beyond local pockets to the entire market and integrate the mechanism within the market software to eliminate the delay in imposing mitigation when warranted. This requires careful design and implementation.

In this period of transition and implementation of the SMD, the Commission's caution in considering an AMP plan is sensible and the particular principles outlined by the Commission are appropriate. The AMP is not perfect, and it could be highly intrusive if not implemented properly and without a systematic approach to maintain the appropriate benchmarks. However, it is hard to define a superior alternative to a properly designed AMP and hard to imagine that the Commission could simply do nothing in the face of a market that was always setting a clearing price at or very near the safety-net bid cap.

The concern with an AMP would come in the implementation, because the potentially intrusive and comprehensive nature of the AMP could significantly exacerbate the problem that the Commission has identified in tipping the balance too much in favor of mitigation to the point of precluding even an approximation of true scarcity pricing. Comparison of the cases of California and New York is instructive. The level of the triggers and the maximum bid caps are much lower and more restrictive in California than in New York. Furthermore, under Commission orders the California rules exclude imports and any significant demand-side bids in setting the market-clearing price. In effect, the California implementation rejects the basic principles that the Commission espouses and makes no attempt to allow for scarcity prices that could at certain times be significantly above the direct cost of the most expensive generator running. Such price mitigation rather than market power mitigation is inconsistent with the SMD framework and could substantially complicate the operation of market power mitigation.

The Commission recognizes that the pressure on the ITP will be to exercise market power of its own as a buyer rather than as a seller, by acting on behalf of customers to reduce short-run prices. This is not an appropriate role for the ITP and it would run counter to all the basic objectives of open access, non-discrimination and the broad efficiency goals of electricity restructuring. Nonetheless, the experience in all markets is that this is a continuing concern of market participants and a challenging balancing act for the ITP. It shows up, for instance, when the ITP is buying “out of market” supplies, a prima facie circumstance of market discrimination and an exercise of monopsony power. Hence, the Commission is sensitive that its rules do not create more opportunities or requirements for deviating from the conditions that would exist in a workably competitive market.

The difficulty with the AMP proposal is that in its breadth of application and flexibility in implementation it could easily become a means of simply reducing prices below scarcity levels, not just market power mitigation. This result would further complicate the transition to a workable market and place even greater pressure on added regulatory interventions to counteract the predictable but unintended consequences. This is the wrong direction. Such price mitigation *per se* is not the Commission’s intent, as evidenced by the extensive discussion of the need for a balance of market power mitigation and scarcity pricing. However, proposals like the AMP place an even greater burden on the Commission to examine the details and avoid the pitfall of turning the ITP into the monopsony buyer who suppresses market prices.

In the case of the AMP proposals, therefore, the Commission should go even further in ensuring that there are not significant “out of market” purchases, so that there is still an opportunity for imports, demand-side bids, or exempt sellers to set a market price with bids that reflect scarcity but not substantial market power. Further, the Commission should go further in considering exemptions to include not only small sellers but also new facilities built after the introduction of open access. The new facilities would still be subject to local market power mitigation rules and the safety net, but for the broad market as a whole, where we should be providing incentives for entry, an exemption from AMP rules for new facilities would provide the incentive and preserve the dynamic of a market where new entrants constitute a primary force for reducing and mitigating market power of existing sellers. These are both features of the New York ISO approach.

In summary, the Commission has the right framework for market power mitigation and recognizes the need to balance with the requirements of scarcity pricing. The use of bid caps in the twin settings of local market power mitigation and a safety net designed as a proxy for demand-side response is consistent with the SMD core elements and the broad objectives of electricity restructuring. The resource adequacy proposal is more problematic, however, and the Commission should attend to the details of implementation of its market power mitigation proposals without assuming that errors can be corrected by the resource adequacy requirement. The details become even more important in the case of the AMP proposals, where the breadth of scope makes AMP mitigation more vulnerable to the error of becoming price mitigation rather than market power mitigation.

VII. RESOURCE ADEQUACY

The Commission has concluded that the nation's markets will need an explicit resource adequacy requirement (RAR) to ensure that the core features of its Standard Market Design result in a workably competitive market. While the Commission's basic prescription for market design is fundamentally sound in its embrace of open, ITP-coordinated spot markets and bid-based, security-constrained economic dispatch with locational prices, the Commission is struggling to define an appropriate RAR that does not inadvertently undermine the SMD's core features and expected benefits. It proposes a possible solution and sets a minimum reserve target, but it seeks public comment on whether its solution is workable and, if not, whether a better solution is available. NOPR ¶473.

The basic features of the proposed solution would begin with the ITP facilitating a regional planning process that developed long-run forecasts of electricity needs. Within each region, a Regional State Advisory Committee would define acceptable resource adequacy (or reserve margin) targets, subject to a minimum reserve level of 12 percent set by the Commission. Looking at least three years out, to allow time for new entrants to compete, the ITP would then allocate to each LSE its proportionate share of the resource adequacy requirement, and expect each LSE to submit conforming resource plans indicating how it would meet the RAR. The ITP would continue to track the LSE resource plans, assessing them for adequacy, resource eligibility, deliverability and so on. It would notify state and local regulators of any deficiencies it perceived in any LSE's plans. LSEs would thus be expected to acquire sufficient resources in advance, either through building their own resources or contracting for them, to meet their ITP-allocated resource needs. Eligible resources could include both supply- and demand-side options, as well as associated transmission enhancements. Following the planning period, the proposal's enforcement mechanisms would then center on what happened in real time in the event that the ITP confronted operating reserve levels less than the minimum requirements. In that event, LSEs that the ITP had previously found "short" in meeting their forward requirements would be subject to penalties on their purchases from the ITP spot markets, and these penalties would increase as the level of operating reserves declined. In addition, "short" LSEs would be subject to involuntary curtailments of their loads before non-short LSEs were curtailed, in the event that involuntary curtailments were required in emergencies. NOPR ¶¶ 474-478.

A. The NOPR's Proposal for a Resource Adequacy Requirement Appears Inconsistent with the Rationale and Core Features of the SMD.

The Commission's search for an RAR mechanism creates dilemmas that arise from the inconsistent policy goals that drive the rationale for an RAR in the SMD NOPR. These inconsistencies strike at the heart of the restructuring argument and become manifest in various forms.

First, the RAR rationale arises primarily from the risks of a flawed approach to market power mitigation, as we note in the previous section. On the one hand, the Commission explains that the appropriate role of market power mitigation is to prevent prices from exceeding competitive levels – but not to prevent prices from reaching competitive levels. If resource investors are convinced that prices will be allowed to clear at competitive levels that reflect shortage costs (or consumers' willingness to pay not to be involuntarily curtailed) when supplies are tight, they will tend over time to support an appropriate level of resource investment. On the other hand, the Commission concedes that market power mitigation measures may inadvertently prevent spot prices from clearing the market at levels sufficient to stimulate the level of investment needed to sustain long-run resource adequacy, no matter how "adequacy" is defined.

NOPR ¶393. In other words, the SMD's proposed market power remedies may well lead to resource shortages unless some RAR mechanism is overlayed on top of the core market design.

Second, the Commission's pursuit of workable markets for generation is largely premised on the belief that consumers will ultimately benefit from moving investment risks and decisions away from the regulatory arena and to the market. The critical observation from market-based decision-making in other industries is that over time private investors will tend to make more efficient investment choices. Perhaps more important, the investors who would reap the benefit from economic investments would bear the risks of uneconomic investments instead of imposing the costs of bad choices on consumers. It is worth recalling that an increasing portion of the new supply that has been built over the last several years has been market-driven; the new plants are not rate-based, and consumers are not (and should not be) on the hook for any poor decisions the investors made. Thus, the market paradigm promises an end to the kinds of costly utility and/or regulatory mistakes that have saddled consumers with billions of dollars in cost overruns and stranded costs. Here, various utility nuclear unit cost overruns come readily to mind, along with expensive PURPA contracts and the State of California's cost overhang from the recent crisis.

In contrast, the Commission's RAR proposal, and probably *all* RAR alternatives, would replace essential features of market-driven investments with regulatory decisions on key issues. As Steve Stoft correctly notes, if the Commission chooses not to allow prices to clear the market and send the right price signals, decisions to invest in adequate new infrastucture will not be made in response to market signals. Instead, they will be made in response to regulatory decisions and administratively defined incentives.[33] If that is true, then an important premise for the benefits of restructuring could be undermined.

[33] Steven Stoft, *Power System Economics: Designing Markets for Electricity*, New York, NY: Wiley-IEEE Press, Part 2.

Third, the Commission's proposal is modeled on the utility obligation to serve and acquire resources. "Our intent is to rely on the traditional state role of enforcing a load-serving entity's reserve obligation." NOPR ¶ 532-533. Overlaying regulatory enforcement on an LSE-centric notion of supply adequacy is incompatible with how markets function. In a true market paradigm, the regulatory obligation to serve and acquire resources would be replaced and transformed by an opportunity to profit from appropriate investments and operational decisions. But this opportunity depends on the expectation that prices will be allowed to clear the market even (and especially) under shortage and near-shortage conditions.[34]

Given these conflicts in Commission goals and policies, it is worth stepping back to see what the NOPR as a whole would create if the RAR proposal were implemented. Is it a genuine market structure, or is it more a reconstituted regulatory structure, dependent upon integrated resource planning, but this time managed by RTOs and other regional institutions? Would investors make – and accept the risks of – resource investment decisions in response to expected prices, or would resource development be driven by regulatory decisions and administratively defined incentives, with only a facade of market competition available at the margin and ratepayers still at risk for regulatory/planning mistakes?

By now, the Commission is aware of the more obvious drawbacks of its particular approach. For example, states with retail choice programs will point out that the proposal is problematic where consumers are allowed to switch from one LSE to another or move between regulated default suppliers and competitive LSEs on short notice. The ITP/RTO would be unable to allocate resource acquisition responsibilities years in advance to each LSE, because

[34] Expectations of receiving market-clearing prices during tight supply conditions are essential not only to peaking facilities but to all other plants, including infra-marginal units that tend to operate at base load. Indeed the bulk of the revenues during high-price peak periods goes to these infra-marginal units and plays

neither the ITP/RTO nor the LSEs could know individual LSE loads more than a month or less in advance.

Other comments will likely note that the complex integrated resource planning functions required to implement the Commission's proposal constitute a substantial undertaking by institutions that do not yet exist (except possibly in the Northeastern ISOs). The lists of tasks is daunting: integrated regional long-run forecasting, integrated aggregate long-run supply assessments, specific (and confidential?) assessments of the feasibility and progress of individual LSE resource plans, development of standards for "qualifying" and "counting" resources, procedures for tracking LSE resource plans over time, resolution of issues of deliverability and deliverability rights, and so on. In addition to these technical hurdles, each region would confront the political challenge of creating the necessary regional institutions that would carry out these assessments and the public processes that would be needed to validate the results. If the history of state resource planning functions is any guide, we may be looking at a decade or more of building the inter-regional planning institutions, staffing them, and defining their analytical and public processes.[35] Under the best of conditions, a fully functioning RAR would be several years away, and it is not clear how resource adequacy would be sustained in the interim.

Apparently aware of the dilemmas it faces, the Commission's RAR proposal tries to have it both ways. On first reading, it purports to create a regulatory/planning structure to encourage and reinforce long-run planning and resource acquisition by load-serving entities. A newly created Regional State Advisory Committee would establish regional reliability goals and

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an essential role in recovering their fixed costs. Thus, price mitigation measures can affect the viability of base-load plants as well as peakers.

[35] The Commission may recall that the California Biennial Resource Plan Update process, whose eventual collapse and rejection by the Commission in 1992-1993 precipitated that state's restructuring efforts, required several years to design and implement. In that case, only one state was involved and there was already a 10-year history of dedicated state involvement in integrated resource planning functions.

measurement criteria, while the ITP/RTO would serve as an unbiased forecaster, assign each LSE its proportionate share of responsibility, and then be the evaluator and periodic monitor of LSE resource plans for adequacy, deliverability and even commercial feasibility. All of the structures of integrated resource planning fashioned by the states in the 1980s would reappear, but with different institutions in charge.

B. Notwithstanding the Long-Run Planning Features, the Commission's Proposal Relies on Short-Run Prices and the Threat of Curtailment to Encourage Resource Adequacy.

Notwithstanding this elaborate planning structure, when it comes to the enforcement mechanism, the Commission's proposal relies on the fundamental premise that short-run prices for uncontracted quantities and the risks of curtailment are what really matter. Under the proposal, LSEs will acquire adequate resources in the forward time period not because they were told to or because there was a planning process but because they seek to avoid increasingly more severe spot market penalties when operating reserves fall below target levels and to avoid the risk of selective, involuntary curtailment of their loads if actual shortages result. NOPR ¶¶529-535.

Of course, if very high short-run prices and curtailment threats are what really matter, then it is not clear what purpose, if any, would be served by the elaborate long-run planning process and associated requirements for institution building. The Commission, RTOs, states and parties could dispense with all of the unneeded complexity and rely on the short-run price incentives and the natural desire of LSEs to avoid selective involuntary curtailments, to the extent these were feasible.[36] LSEs might then make long-run forward commitments, either

[36] Selective curtailments would be feasible if LSEs were only regulated utilities with defined service/control areas, but such curtailments would often not be possible where LSEs were competitive entities with no pre-

through building or contracting. But a rational LSE, particularly one functioning in a retail choice environment, might also conclude that it should avoid the risks and uncertainties of making additional resource commitments years in advance as a result of the RAR. It might contract "forward" to avoid spot market volatility and curtailments, but "forward" could mean only a few weeks or even days before real time. Short-run contracts could then be tailored to hedge risks in proportion to more accurately predicted loads and the potential for actual shortages and curtailments.

If that is the more likely result of the Commission's proposal, then the design task would be to set the penalties for spot market usage to provide the right incentives for forward commitments that would, in turn, lead to adequate investment levels. Here the Commission acknowledges that penalties starting in the range of $500/MWh above the (mitigated) spot prices are *illustrative* only. To work as they should, the penalties would probably need to be *much* higher, defined by shortage costs and the willingness of loads to pay to avoid involuntary curtailment. NOPR ¶530-532. Penalties would need to be high enough to confront affected LSEs with a rationale choice between contracting forward, or paying very high short-run prices and/or facing curtailment. Resource investors would logically want penalties high enough to sustain the desired investments levels while making them at least indifferent to whether they received the spot prices plus penalties or LSEs signed long-run contracts with them to avoid the same prices.

In this scenario, further development of the Commission proposal might lead to something like the "capacity adder" used in the UK's original pool. Other considerations would then drive the Commission proposal to mimic that concept more closely. For example, once the

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defined areas. As a practical matter, selective curtailment would be at least difficult and probably unworkable in states with meaningful retail choice programs. At present, the distribution utilities essentially irrelevant and overly complex advance planning features were jettisoned, it would become apparent that there would be no mechanism to distinguish LSEs that were “short” in some forward period from those who were “adequate” or “long.” Without a means to distinguish who should or should not be subject to penalties, *all* LSEs and buyers that used the spot market would need to be subject to the same spot market penalties.

In addition, the Commission asks who should receive the penalty revenues? NOPR ¶534. Logically, as with all other spot market prices paid by buyers, these revenues should go to those suppliers that provide the resources in real time, whether that means the LSEs that were “long” or just suppliers with additional uncontracted capacity. In other words, *all buyers in the spot market would pay the spot prices and penalties and all suppliers in the spot market would receive the spot prices and penalties*. The transition to relying on short-run prices – including spot prices and penalties – to clear the market would be complete.

Hence, the good outcome of the penalty approach would end up with the charge applying formally to all spot transactions. And the penalty should be essentially the same as would have been produced by market-clearing on its own. To the extent that the penalty is higher than the market-clearing price, shortage conditions would provide incentives for market participants to offer only balanced schedules from which they would not be willing to deviate. This would produce the unintended consequence of reducing flexibility precisely in the circumstances where it is most difficult to operate the system.

The Commission proposal could logically evolve toward a system in which short-run prices would do more or less what the spot markets would do if prices were allowed to clear the markets at all times, including periods of shortages or near shortages. If the political judgment is

implement load curtailment and it is not clear how the ITP could be responsible for selective curtailments.

unwavering that this solution is not acceptable, then the alternative would be to begin the search again for a capacity requirement that "solves" the adequate investment problem without unduly distorting the short-run markets, a search that so far appears to have produced no entirely satisfactory solutions.

C. <u>Proposals to Enforce Long-Run Resource Acquisition Cannot Avoid the Issues Faced by ICAP Proposals.</u>

Despite the Commission's (sometimes valid) criticisms of installed capacity (ICAP) requirements, all of the issues in ICAP would arise if the Commission attempted to "fix" its own proposal along the path of a forward resource obligation. Faced with the unwillingness to let prices clear the markets, but a need to provide the "missing revenues" to ensure adequate investments, the Commission would be driven to the same kinds of solutions and proposals that are currently under development by the Northeast Joint Capacity Adequacy Group and indeed by every other emerging RTO region.

In the final analysis, there is no escaping the fundamental choice (as Larry Ruff has noted[37]) between letting the spot markets clear at prices that reflect scarcity/shortage costs or confronting the many difficult issues in designing ICAP approaches. If the Commission is unwilling to confront the challenges of market-clearing prices, then it must figure out how to collect money from consumers and pay it to those generators and demand-response providers that must provide reliability in real time, especially during peak periods. It must find a means to encourage and enforce long-run commitments without undermining retail choice.[38]

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[37] See, Larry E. Ruff, "Assuring Resource Adequacy: Concepts, Options and the SMD," presentation to the Massachusetts Electricity Restructuring Roundtable, October18, 2002.

[38] It is this issue that has led the Joint Capacity Adequacy Group to consider forward capacity auctions coordinated by the ITP. Under this approach, the ITP would centralize initial supply acquisition in the long run (to allow for new entry) while allowing self supply arrangements to receive credit for the resources they bring to the auction. More frequent reconfiguration auctions could be used to allow parties to align their

Because the choice between letting markets clear and imposing ICAP-like mechanisms cannot be avoided, the Commission should refrain from telling the ISOs in the Northeast that they must replace ICAP while telling them that a market-clearing alternative is out of the question. ISOs and participants in the region have concluded that the market-clearing mechanism is not politically feasible at this time and so are working through the Joint Capacity Adequacy Group and other forums to solve the issues in their current ICAP mechanisms. While we believe the market-clearing alternative has considerable merit and should not be dismissed, for reasons discussed below, we do not dispute the parties' perceptions of the current political assessment or the value of continuing to work through the various ICAP issues.

D. <u>The Commission Should Reexamine the Option of Allowing Prices to Clear the Spot Markets.</u>

1. Is allowing prices to clear the markets viable?

The question remains whether allowing prices to clear the markets during shortage and near-shortage conditions should be dismissed out of hand as politically untenable or whether the Commission should at least give the idea a further hearing and perhaps allow it as a rational choice for those emerging market regions willing to consider it. Here it may be helpful first to ask, "what would it take to make electricity markets more successful?"

It is now accepted wisdom that a primary flaw in existing markets is the absence of appreciable levels of demand-side response to market prices.[39] This flaw can be traced directly to inefficient rate designs at the state and local levels and to the absence of interval metering that

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positions with expected load responsibility. The central acquisition costs would be allocated to LSEs much closer to real time, when expected load responsibilities were better known.

[39] E.g., see, Severin Borenstein, "The Problem with Electricity Markets: Understanding California's Restructuring Disaster," *Journal of Economic Perspectives* 16(1) (Winter), 191-212.

can measure usage at the market's hourly and sub-hourly intervals, as well as associated devices that let those customers who are sensitive to price know when prices exceed levels that are important to them. The Commission emphasizes this market defect (NOPR ¶390), but there is little the Commission can do directly to remedy this flaw. Only the states and local regulators can fix this by implementing forms of real-time pricing and support for appropriate meters, and they should be encouraged to do so with all deliberate speed, at least for large commercial and industrial customers.

In the meantime, the Commission could require that wholesale prices reflect market-clearing levels, creating stronger incentives for states and local regulators to devise means to more closely align short-run wholesale prices to retail rates. That reform would then encourage states and LSEs to pursue demand-side initiatives that permit a larger range of customers to receive and respond to changes in wholesale prices. There is nothing new about this concept: even in fully regulated regimes, it has always made sense for state and local regulators to align retail rates more closely with utility marginal costs as they vary across time and location. Prior to market restructuring, regulators routinely and periodically adjusted retail rates to reflect changes in utility procurement costs, seasonal hydro conditions and short-run fuel costs. The emergence of transparent hourly and sub-hourly market prices based on locational marginal pricing presents an opportunity for regulators to substantially improve on a concept with which they are already familiar.

Excessive price mitigation, whether stemming from an overreaction to market power concerns or a desire to smooth out spot price volatility, is highly detrimental to efforts to increase efficient demand-side responses. RAR-type proposals attempt to make a virtue of this, but wind up making the problem worse. If demand-side response is artificially held down by depressed prices, then demand and consumption are higher than the underlying cost structure would warrant, which means that customer demand can only be met with more capacity than would otherwise be justified. One way or another, consumers must pay for this excess capacity.

2. Concerns over spot price volatility are misplaced.

A central element of the Commission's SMD proposal is to facilitate long-term contracting. To the extent that customers or their suppliers have arranged in advance to have long-term contracts, volatility in the spot market has little effect on their average prices. The price incentives would still operate at the margin, as they should to stimulate appropriate demand-side response. However, the huge transfers of wealth witnessed in California would not be repeated. It was the failure to facilitate long-term contracts that was the centerpiece of the California crisis that converted a serious event into a full-scale financial crisis.

Given the SMD's strong support for easy long-term contracting to hedge energy requirements, the concern over spot price volatility seems misplaced. Moreover, as a practical matter, those customers deemed to be too small to justify interval metering would not face hourly spot market prices. At most, monthly meter reading and billing practices would mean that small customers would see, at worst (best), monthly averages of spot prices, whether or not their states allowed retail choice. It is instructive to note that various states have experimented with the issues of designing an efficient default supply approach, and some have concluded that the default supply obligation should be frequently auctioned and reallocated – as often as every two or three months. The goal is to narrow the gap between default supply prices and average wholesale market prices, a gap that serves only to distort retail choice decisions. Hence, some states are not far from the equivalent of monthly billing for default suppliers at the average wholesale spot price.

Where most/all customer are still served by the local utility under bundled rates, state and local regulators will have opportunities to improve the efficiency of those rates by ensuring that the "generation component" can be periodically adjusted to reflect the actual mix of utility costs and wholesale prices. But the important point is that customers in these areas would not see wholesale spot prices or be affected by short-run spot price volatility. Hourly volatility is irrelevant to them and mostly irrelevant to their respective utilities, which have the ability to hedge this volatility through self-supply and contracts of varying lengths.

As for customers that are large enough to justify interval metering and billing systems – and as metering improves, "large enough" is getting smaller – the means for gaining direct access to the wholesale spot market are closer at hand. These customers are large enough to participate in retail choice programs and, if so, they have the means to contract to hedge spot market risks to any degree they find reasonable. In states without explicit retail choice, such customers could easily be assigned rates defined in part by real-time spot prices. Several states are considering this option and it should become more widespread as transparent spot prices from ITP-coordinated spot markets become available.

3. Allowing prices to clear the markets during shortage and near-shortage conditions would have helped in California.

If spot price volatility is not the problem, then what is? What is left is the concern that the NOPR's restructuring will expose regions with otherwise stable (and supposedly reasonable) rates to the kinds of prolonged wholesale price explosions that visited California. Here the Commission must sort through the competing claims and get to the bottom of why prices rose so dramatically in California and the West generally and why they stayed that way for so long. After all the analysis is done, we believe the Commission will conclude that California's crises were a combination of the imperfect storm of adverse demand-supply fundamentals, a series of acknowledged mistakes in the State's restructuring rules, an admittedly flawed market design, and a systematic failure of elected and appointed officials at all levels to understand what needed to be done. There may have been market manipulation that had some effect on average prices, but even absent that manipulation, the fundamental problems would have remained.

Importantly, the Commission's SMD NOPR addresses some of these flaws directly and others indirectly, and it is up to the states and local regulators to learn the remaining lessons. What emerges from this analysis, however, is the conviction that if real-time pricing and exposure to spot prices at the margin had been implemented, the demand-side response would have proved invaluable in mitigating high prices – whatever their cause – and would have largely avoided the utilities' financial crises and the need for massive state intervention as the buyer for all consumers. If restructuring rules had allowed long-term contracts to be a larger part of the mix, as the SMD proposes, the spot price increases would not have translated into huge increases in utility liabilities or customer bills. Even if the high prices are ultimately judged to have been partly the result of deliberate withholding or other market manipulation, allowing the markets to clear and allowing consumers to respond to those prices would have mitigated the prices and helped tame the market manipulation. In other words, instead of creating the problem, letting prices clear the markets, along with exposure to spot market prices at the margin, would have helped solve the problems in California.

Part of the price of being an early implementer is that California was not yet ready for these remedies, and imposing them in the middle of the crises would undoubtedly have been painful – perhaps unacceptably so. But what does this mean for going forward? Should states place their consumers in a false cocoon and hope that they never experience California-like conditions? Or should they learn from California that excluding long-term contracts and preventing consumers from seeing and responding to short-run prices is a poor and ultimately unsuccessful way to protect consumers from high electricity costs?

In summary, the Commission's proposals for RAR tackle a problem that may not exist, and may not have a solution in any event that is consistent with the basics of the SMD. The feasibility of targeted curtailment is not obvious, and the use of penalties for undercontracting appears inferior to the simpler process of allowing prices to clear the energy and reserve markets. Long-term contracting should be made easy, but not mandatory. The emphasis should be on financial hedging contracts, not explicit capacity requirements. And a focus on developing demand-side participation would target the real source of concern. Replacing the old utility-run integrated resource investment programs with the ITP-run integrated resource investment programs would ratify the criticisms of open access and non-discrimination as not worth the effort.

The alternative to allowing prices to clear the markets is not easy, and there is a slippery slope toward replacing the market with regulation of another kind. The Commission should act with caution not to prescribe solutions without a more careful consideration of what is required and what is possible.