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Summaries of Initial Comments Filed with FERC Concerning the SMD NOPR: Docket No. RM01-12-000

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Several issues of broad concern are evident in the comments submitted on the Federal Energy Regulatory Commission's (FERC) Notice of Proposed Rulemaking (NOPR) docket no. RM01-12-000.

1. Many state commissions (especially those in the Southeast and West) object to FERC's assertion of jurisdiction in the NOPR. Other states raise no jurisdictional questions. Some have not yet submitted comments. Of the 29 state commissions that have commented, 23 have raised questions concerning jurisdictional aspects of the NOPR. Some of the jurisdictional issues raised are: (1) the sufficiency of evidence presented to demonstrate undue discrimination; (2) authority of FERC to assert jurisdiction over bundled retail transmission service; (3) the authority of FERC to assert jurisdiction over resource adequacy and generation planning; (4) the possible violation of the *Mobile-Sierra* doctrine; (5) conflicts with existing state and federal laws; and (6) whether FERC has the authority to grant ITPs control over transmission assets. Several utility companies also share state concerns about jurisdictional issues. These utility companies worry about getting caught in the middle of a jurisdictional contest between FERC and the state commissions. They fear this would lead to inconsistent regulations and trapped costs. Several utilities suggest that FERC modify the NOPR to ensure state regulatory participation and respect state jurisdiction.

2. A number of comments that raise jurisdictional concerns also broach the general policy issue of the costs vs. benefits of implementing Standard Market Design (SMD).

3. A related jurisdictional question raised is the status of non-jurisdictional entities under SMD. Non-jurisdictional entities fear that the NOPR implies they will be converted into jurisdictional entities under SMD. They seek clarification from FERC that this implication was unintentional. Conversely, some investor-owned utility companies make the case that non-jurisdictional entities should submit to reciprocity tariffs.

4. A concern about the timeline for implementation of SMD was nearly ubiquitous in the comments. Wide support exists among all categories of commenters for the proposition that, if implemented at all, SMD needs to be phased in. Moreover, many comments point out that, due to regional variation, some amount of flexibility is required in implementing SMD. Of the 29 state commissions commenting, 21 expressed concerns with the implementation timeline, with 9 of those calling for complete withdraw of the NOPR.

5. Besides the jurisdictional concerns, many issues regarding incentives for investment in infrastructure are raised. Although the comment period for transmission planning and pricing has been extended until 10 January 2003, several broad concerns are already apparent. Several comments note that LMP alone may not provide sufficient incentives for investment. Questions have been raised concerning the sufficiency of revenue requirements or CRRs. If transmission capacity increases will the value of CRRs decrease? The adequacy of merchant transmission facilities for meeting

regional needs is also discussed. A related issue is cost recovery. State regulators tend to prefer participant funding. Others, however, suggest that FERC allow for a combination of participant funding and rolled-in pricing. One utility company, concerned that these issues will bog down implementation of the entire SMD, proposes that FERC sever these aspects from the NOPR. One point of agreement is that the NOPR lacks sufficient detail and clarity in regard to transmission investment.

6. The issues involved with market power mitigation produced a wide variety of comments. Most comments agree that all steps must be taken to make sure the market monitor is an autonomous entity under FERC. There is also a consensus, particularly articulated by the energy providers, that it would be an improper delegation to grant a market monitor the authority to impose penalties. Some state commissions have requested that any information available to the market monitor also be made available to the relevant state commissions. They further argue that claims of confidentiality should not be allowed to delay or hinder the tender of information. A joint comment by six state utility commissions suggests that, because market monitoring and mitigation is so important to the public interest, FERC should propose this segment of the NOPR as a separate rule.

7. Commenters disagree about the role of ITCs. Many state commissions believe that ITCs should not serve as ITPs because they would lack independence. Several investor-owned utilities suggest, however, that ITCs be allowed to serve as ITPs or be given greater responsibility under the SMD. Others shared the state commissions' concerns about functional separation of ITCs and ITPs.

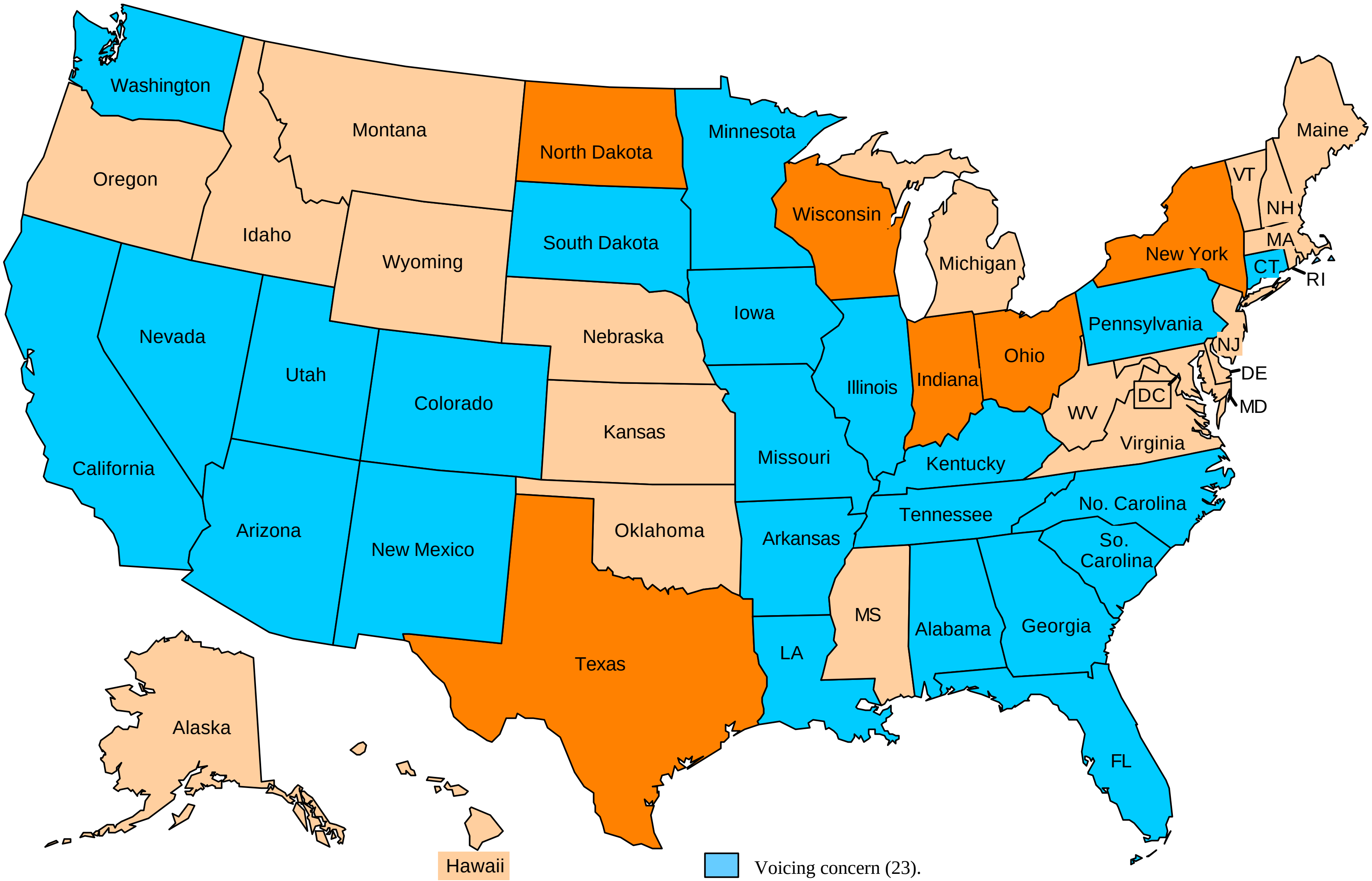
8. Elimination of native load preferences is an issue taken up mainly by state commissions. Several state commissions assert as a preliminary matter that a utility favoring its own retail load to comply with state laws does not amount to undue discrimination. Several states point out that this proposal might increase costs or reduce reliability for native load customers. It is suggested that native load should retain scheduling priority. In contrast, one particular state public utility commission believes native load preferences are at odds with a properly structured competitive market and should be avoided.

9. Many comments have mentioned CRRs, especially relating to the issue of limiting them to financial rights rather than physical rights. But some have deferred their remarks on CRRs until the 10 January round of comments. This and other issues will be addressed further in the future.

10. Although also an issue postponed until the 10 January round of comments, concerns have been raised about the role of RSACs or MSEs. There is a general concern about what an "advisory" role for the states would entail. State commissions are worried that the RSAC scheme would interfere with their regulatory authority. The RTOs and ISOs have a countervailing concern that the RSACs might be granted a separate legal authority. Several state commissions suggest a joint commission as provided for in §209 of the FPA as an alternative means to link FERC and the states.

State Commission Comments Voicing Concern About the Extent of FERC's Assertion of Jurisdiction in the SMD NOPR

as of 8 January 2003



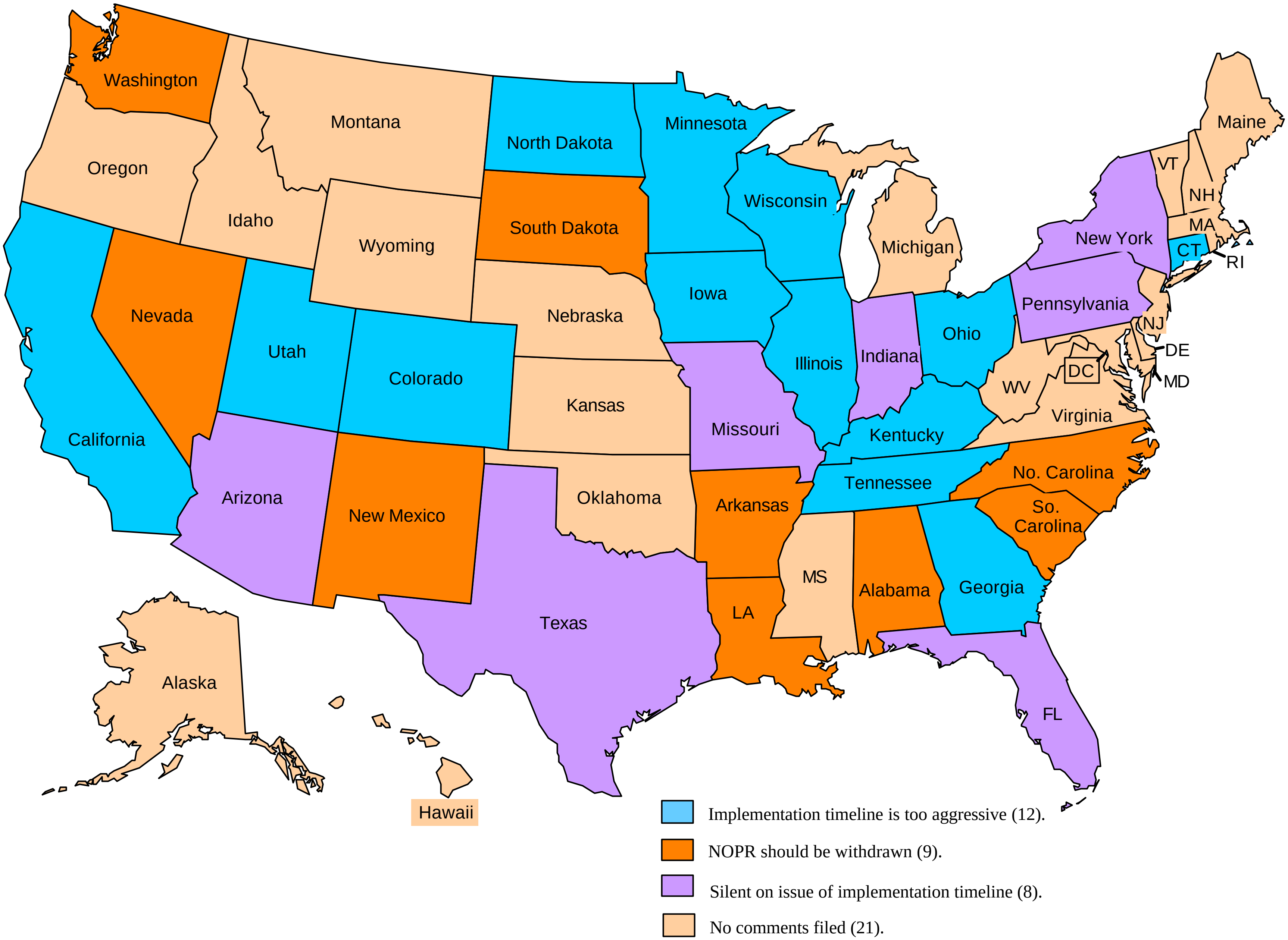
Voicing concern (23).

Not voicing concern (6).

Comments not yet filed (21).

State Commission SMD NOPR Comments
Regarding Implementation Timeline

as of 8 January 2003



Initial SMD NOPR Comments
15 November 2002

Commenting Entity	Type of Entity	Summary of Comment
AL Public Service Commission	NARUC Member	AL PSC summary
Alliant Energy	Investor-Owned Utility	Alliant summary
American Electric Power	Investor-Owned Utility	AEP summary
American Transmission Co.	Stand-Alone Transmission Company	American Transmission summary
AR Public Service Commission	NARUC Member	AR PSC summary
AZ Corporation Commission	NARUC Member	AZ CC summary
Buckeye Power	Non-Jurisdictional Utility	Buckeye summary
CA Public Utilities Commission	NARUC Member	CA PUC summary
Carnegie Mellon Electricity Industry Center	Academic Research Institution	CEIC summary
Cinergy	Investor-Owned Utility	Cinergy summary
CO Public Utilities Commission	NARUC Member	CO PUC summary
Duke	Investor-Owned Utility	Duke summary
Edison Electric Institute	Trade Association	EEI summary
Edison Mission Energy	Power Producer & Marketer	EME summary
Exelon	Investor-Owned Utility	Exelon summary
FL Public Service Commission	NARUC Member	FL PSC summary
GA Public Service Commission	NARUC Member	GA PSC summary
IA Utilities Board	NARUC Member	IA UB summary
IL Commerce Commission	NARUC Member	IL CC summary
IN Utility Regulatory Commission	NARUC Member	IN URC summary
Joint RTOs & ISOs	RTOs & ISOs	RTOs & ISOs summary
KY Public Service Commission	NARUC Member	KY PSC summary
LA Public Service Commission	NARUC Member	LA PSC summary
MN Department of Commerce	NARUC Member	MN DOC summary
MO Public Service Commission	NARUC Member	MO PSC summary
National Rural Electric Cooperative Association	Non-Jurisdictional Utilities	NRECA summary
NC Utilities Commission	NARUC Member	NC UC summary
ND Public Service Commission	NARUC Member	ND PSC summary
NM Public Regulation Commission	NARUC Member	NM PRC summary
NV Public Utility Commission	NARUC Member	NV PUC summary
NY Public Service Commission	NARUC Member	NY PSC summary
OH Public Utilities Commission	NARUC Member	OH PUC summary
PA Public Utilities Commission	NARUC Member	PA PUC summary
PG&E	Investor-Owned Utility	PG&E summary

PJM Interconnection	RTOs & ISOs	PJM summary
PJM Transmission Owners Group	Investor-Owned Utility	PJM TO summary
SC Public Service Commission	NARUC Member	SC PSC summary
SD Public Utilities Commission	NARUC Member	SD PUC summary
TN Regulatory Authority	NARUC Member	TN RA summary
TRANSLink	Investor-Owned Transmission Operator	TRANSLink summary
TX Public Utilities Commission	NARUC Member	TX PUC summary
US Department of Energy	Federal Agency	DOE summary
UT Public Service Commission	NARUC Member	UT PSC summary
WA Utilities and Transportation Commission	NARUC Member	WA UTC summary
WI Public Service Commission	NARUC Member	WI PSC summary
Williams	Power Producer & Marketer	Williams summary
Xcel Energy Services	Investor-Owned Utility	Xcel summary

The Alabama PSC recommends that the FERC withdraw the SMD NOPR because:

1. FERC lacks the authority to regulate retail matters of state policy subject to state jurisdiction, including: bundled retail service, retail demand response, and generation resource adequacy (pp. 4-5).
2. State regulated utilities are obligated by state law to serve native load customers. Thus, native load preferences do not amount to undo discrimination (p. 5).
3. Theoretical harm to competition is not a sufficient basis for FERC to impose a national SMD. Less intrusive measures exist (pp. 5-7).
4. The proposed SMD will not serve the public interest in Alabama. Moreover, FERC has not done a cost/benefit analysis in regard to the impact of implementing the SMD (pp. 7-10).

Alliant Energy (Alliant) supports the goals of SMD. However, Alliant encourages FERC to allow for a more gradual implementation of SMD allowing for regional variation. Alliant also endorses the position, articulated by the Edison Electric Institute in its comments, that instead of mandating an implementation date for SMD, FERC should establish a date when each region or ITP must file an SMD proposal for that region.

Regarding CRRs, Alliant believes they should be considered financial tools but there should be no physical characteristics associated with them.

Concerning system security, FERC should continue to allow NERC to develop cyber security standards. FERC should adopt NERC's revised "Cyber Security Standards for Electric Wholesale Market Operations". However, Alliant objects to the requirement that public utilities be put in the position of gatekeeper for self-certification requirements of non-jurisdictional entities.

American Electric Power (AEP) commends FERC for the SMD NOPR. AEP supports the overall policy goals of the NOPR. It does have concerns about the scope and implementation schedule of SMD. AEP supports prompt implementation of the core elements of SMD, but FERC should take a flexible, phased implementation approach that deals with the legitimate concerns of stakeholders, including state regulators. Non-core issues (such as the transmission planning process, resource adequacy requirements, and market mitigation issues) should be handled in a separate proceeding. The proper resolution for these issues will vary across regions, so FERC should permit as much regional variation as necessary.

1. AEP is concerned with cost recovery for utilities. SMD implementation will be costly. Utilities will not be assured recovery of these costs without the express approval of state commissions. Lacking state acceptance of SMD, FERC's proposals will amount to unfunded mandates for utilities. Currently, may state commissions are opposed to SMD. It is inequitable to place utilities in the middle of jurisdictional contests between states and FERC. The only way to ensure utilities will not be responsible for the costs of SMD will be for FERC to work with the states to create a cost recovery solution.
2. Rates for bundled retail customers should be decided regionally.
3. FERC should clarify that it does not intend to allow retail bypass. AEP calls attention to the comments of EEI concerning §9.1 of the NAS tariff (see EEI comments, pp. 34-35).
4. FERC should preserve limitations of utility liability.
5. AEP is concerned that the scope of the proposed system security standards and the aggressive timeline for implementation will require transmission owners to incur substantial costs.
6. AEP strongly opposes any attempt to delegate government functions, such as assessing penalties for wrongdoing to the Market Monitor.
7. The SMD implementation timeline is too ambitious and should be extended.

American Transmission Company LLC (ATC) believes that the structural separation of transmission facilities from power generation and marketing activities in conjunction with adoption of the proposed new SMD is the most direct means of achieving FERC's goal of more efficient and competitive wholesale markets. While the NOPR recognizes the importance of stand-alone transmission companies (SATCs), it does not require complete separation of generation and market activities. ATC feels that an adequate and reliable transmission network that is owned and operated by stand alone companies with no role in energy generation, marketing, or merchant activities is the best way of ensuring competitive markets. Thus, FERC should (1) adopt rules that do not pose obstacles to the establishment of such companies; (2) rely on these entities as the primary vehicle for transmission planning and development and; (3) assure that its market design proposal does not incorporate governance, cost recovery, or risk allocation mechanisms that undermine the financial viability of SATCs or otherwise restrict their access to capital market on reasonable terms.

ATC believes that the NOPR could pose a significant threat to the financial viability of SATCs because of its failure to provide appropriate limitations on liability. ATC opposes FERC's proposal to have transmission operators serve as the "guarantor" of the value of CRRs. CRR shortfalls are the result of multiple factors. ATC believes that FERC should adopt a policy that assigns risks to those market participants best able to manage those risks.

The NOPR endorses the concept of "merchant" transmission facilities as an alternative for meeting regional needs for new transmission infrastructure. ATC believes that such merchant facilities (i.e., projects promoted and funded by third parties who retain certain property rights) are realistic options for only a very small portion of transmission system needs. Moreover, merchant transmission projects are especially problematic for network additions.

Finally, ATC opposes the "single stakeholder group" restriction of participation of certain entities in the RTO/ITP stakeholder advisory groups. It is reasonable to assume that an SATC's passive utility owners would choose to participate in one of several stakeholder groups that reflects their core business focus; however, because of the NOPR's proposed restriction, such participation could preclude ATC, as an "affiliate", from separately participating in the transmission owner stakeholder group.

The Arkansas Public Service Commission (APSC) continues to support the development of competitive wholesale electric markets but strongly objects to the broad, over-reaching proposals contained in the NOPR. APSC contends that FERC should not proceed with its proposed rule because the underlying factual assumptions and legal foundations are erroneous or, at best, unsupported by the evidence.

1. APSC encourages FERC to use its existing statutory authority under the FPA to impose appropriate sanctions on any transmission owner that engages in prohibited practices (p. 5).
2. According to §201(b)(1) of the FPA, bundled electric service provided at retail is under the purview of state regulators (pp. 5-7).
3. The greatest misconception in the NOPR is that the industry is undergoing a competitive transition. This is incorrect. Roughly two-thirds of the states retain regulation of utility generation, and these states are not undergoing a competitive transition. The Southeast states expect to retain the regulated, integrated utility service for the foreseeable future (p. 7).
4. An additional legal problem that plagues the NOPR is the lack of procedural due process. This is created by a lack of sufficient specificity in many provisions. Therefore there is not adequate notice of just what SMD would be if the rule were adopted (pp. 8-9).

The initial comments of the Arizona Corporation Commission (AZ CC) agree with the abstract goals of the SMD proposal, but raise substantial concerns with its application in Arizona. The AZ CC questions whether the concerns that prompted the SMD NOPR would not be better addressed on a case-by-case basis in RTO orders. Such a method would promote regional flexibility, a particular concern of western states.

1. Legal issues.
   1.1. The SMD NOPR's assertion of federal jurisdiction over bundled retail rates (pp. 2-5).
   1.2. The proposed SMD may violate the Mobile-Sierra Doctrine [*United Gas Pipeline Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956); *Federal Power Comm'n v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956); *see also Atlantic City Electric Co. v. Federal Energy Regulatory Comm'n*, 295 F.3d 1, 14-15 (D.C. Cir. 2002)]. According to these precedents, FERC may only abrogate or modify private contracts if required by the public interest (pp. 5-6).
2. Technical comments.
   2.1. Interim tariff.
      2.1.1. Seams issues are not created by different rules for bundled retail service and wholesale and unbundled transmission (p. 6).
      2.1.2. Rate recovery of the costs of facilities that function solely to deliver power to local retail customers should remain under state jurisdiction (*Id.*).
      2.1.3. The claim that differences between wholesale and retail transmission are unduly discriminatory is unfounded. In fact, placing bundled retail load immediately under the existing *pro forma* tariff would create discriminatory practices toward retail customers by degrading transmission access rights. Offering CRRs would not placate such discrimination (pp.6-7).
   2.2. Independent Transmission and Markets.
      2.2.1. The deadlines for implementing the SMD are unworkable (p.7).
      2.2.2. The proposed new Network Access Service disregards pre-existing transmission rights of network load (pp.8-9).
   2.3. Market power mitigation and monitoring.
      2.3.1. The SMD NOPR fails to provide real solutions to the problems of lack of demand response and load pockets (pp.9-10).
      2.3.2. Should market monitors regulate the ITP? (p.11).
      2.3.3. Monitoring of the forward markets is necessary (*Id.*).
      2.3.4. States and regional bodies should be granted more authority to monitor markets (*Id.*).
   2.4. The AZ CC supports the proposal for ITP governance. However, board members and their immediate family should be required to divest all interests in participating companies (p. 12).
   2.5. Regarding system security, relying on NERC for standards rather than NAESB will assure that the reliability will have precedence over commercial expediency (pp.12-13).

Buckeye Power, Inc. and Ohio Rural Electric Cooperatives (Buckeye), as non-profit organizations whose sole purpose is to provide for the best practicable electric service at the lowest practical cost to consumers, support the SMD NOPR to the extent that it will achieve that purpose and will vigorously oppose it to the extent that it impedes that purpose.

1. Electric distribution cooperatives should not be subject to FERC jurisdiction.
    1.1. Historically, electric distribution cooperatives financed through RUS programs have not been considered "public utilities" subject to FERC jurisdiction. Buckeye expresses grave concern about the possible unintended consequences of FERC's decision to assert jurisdiction over the transmission component of bundled retail transaction. Buckeye believes that it would be contrary to the FPA, as well as the RFA, for FERC to assert jurisdiction over electric distribution cooperatives engaged solely in retail distribution service. Moreover, this would be poor public policy in that it would subject very small non-profit consumer-owned entities to extremely burdensome regulation and costs for no justifiable purpose.
    1.2. Likewise, FERC's suggestion that some type of "bright line" test for determining what type of electric lines are subject to FERC jurisdiction under the FPA as "transmission" lines could have the same unwise and unlawful consequences. FERC cannot extend the scope of its jurisdiction to local distribution facilities by rulemaking, and Buckeye assumes that FERC does not in fact have any such intention. FERC should insert express language in any SMD final rule that states that electric distribution cooperatives shall not be subject to FERC's general jurisdiction by virtue or either voltage level of any part of their electric distribution facilities or the rendition of bundled retail transmission service.
2. All zonal license plate transmission rates should be eliminated in favor of postage stamp rates covering a broad range.
3. All vestiges of transmission rate seams within a single market region, such as the state of Ohio, should be eliminated.
4. The NOPR is fatally flawed in that it places complete reliance for achieving long-term transmission system adequacy in it LMP, CRR, and participant funding provisions. Buckeye is concerned that the NOPR contains no mechanism for requiring the ITPs themselves to make required investments in the facilities. The NOPR unfairly places the burden on LSEs to finance the cost of additional transmission facilities. This is wrong. The essence of public utility responsibility under both common law and statutory law is the requirement that a public utility provide adequate service on a non-discriminatory basis at a reasonable price. If FERC does not impose any direct responsibility on ITPs to make required investments, it will fail in its basic regulatory responsibility.

The California Public Utilities Commission (CPUC) expresses serious concerns regarding the SMD NOPR. Some of these concerns include:

1. Need for regional variation (pp. 5-6).
2. Need for more gradual reforms (p. 5).
3. The legal basis for the SMD rests on allegations of undue discrimination. FERC believes that vertically integrated utilities are inherently discriminatory (pp. 6-7).
4. Despite the jurisdictional limits listed below, in the name of transforming the wholesale industry, FERC plans to disintegrate the retail system, turning the joint federal-state regulatory structure on its head (p. 8).
   - 4.1. The NOPR proposes a transfer of authority from the states to FERC over demand forecasting, resource planning, demand-side management, marketing, etc. This will result in FERC assuming jurisdiction over retail rate design. This contrasts with FERCs recent argument that it lacked jurisdiction under §201 of the FPA over bundled retail sales and was not required to regulate that transmission component under §206 (*See* Brief of the FERC. Supreme Court of the US. *New York v. FERC, Enron v. FERC*. Nos. 00-568 and 00-809. May 2001. P. 50.) (pp. 7-8).
   - 4.2. Section 201(b) of the FPA bars FERC from jurisdiction over generation facilities. This is in conflict with the resource adequacy provisions of the NOPR (p. 8).
   - 4.3. According to §202(a) of the FPA, FERC may provide for voluntary participation in interconnection agreements. ITPs are such an agreement. Under Orders 888 & 2000, participation in ISOs or RTOs was voluntary. The proposed rule would require utility agreements with ITPs. This clearly violates the FPA. This interpretation was confirmed recently by the D.C. Court of Appeals in *Atlantic City Electric v. FERC* (p. 8).
5. Section 206(b) of the FPA places the burden of proof upon FERC in a finding of undue discrimination. The evidence, mainly allegations and hypotheticals, of undue discrimination in the NOPR is weak. The proposed remedy is completely disproportionate to this alleged undue discrimination. Moreover, much of the evidence cited by FERC amounts to due discrimination—the intended result of state regulatory practices (pp. 9-13).
6. Policy Analysis of the NOPR.
   - 6.1. What Californians gain is minimal.
     - 6.1.1. Undue discrimination and seams problems are largely phantom issues (p. 13).
     - 6.1.2. Voluntarily developing RTOs are already developing “best practices” for dispatch and operations (p. 14).
     - 6.1.3. Western states do not need FERC’s help for infrastructure investments (pp. 14-15).
   - 6.2. Californians may suffer considerable loss.
     - 6.2.1. Native load loses historical protections (p. 15).
     - 6.2.2. Proposed merchant transmission will be more costly (pp. 15-16).
     - 6.2.3. Market model for industry requires overbuilding of transmission (pp. 16-17).

6.2.4. System expansion under the SMD would occur without meaningful public input (pp. 17-18).

7. Before engaging in a major and unprecedented restructuring of the entire wholesale electric industry, FERC must provide convincing evidence that the benefits of the SMD proposal outweigh the costs. FERC should first conduct a serious cost benefit study (pp. 18-21).
8. RTO governance issues.
   8.1. A major problem with FERC's proposal is its decision to allow stakeholder groups to choose the Board of Directors of the RTOs and ITPs (pp. 21-23).
   8.2. FERC does not have the authority under the FPA to direct the composition of the board of a public utility such as an ITP or RTO (pp. 23-26).
   8.3. There are a large number of RTO structures that can ensure open non-discriminatory access to the transmission system (pp. 26-28).
   8.4. FERC's proposal to have stakeholders choose the directors of the RTO is not in the public interest (pp. 28-32).
   8.5. The board of directors for the RTO likely to be chosen by FERC's proposed selection process will lack the diversity of backgrounds, skills, and talents found on the boards of almost all other corporations (pp. 32-33).
   8.6. The board of directors for the RTO will lack accountability for the consequences of their actions (p.34).
   8.7. It is administratively onerous and in some cases unclear, how a public utility that does not choose to join an RTO can meet the ITP requirements FERC proposes (pp. 34-36).
9. The CPUC has serious concerns about the inadequacy of the market monitoring and mitigation options proposed in the NOPR. The proposed measures will not be effective in preventing prices from rising to the high levels of the net bid cap ($1000/MWh). CPUC will address this issue more fully in its January comments (pp. 36-37).

Seth Blumsack, Dmitri Perekhodtsev, and Lester B. Lave of the Carnegie Mellon Electricity Industry Center (CEIC) comment on the issue of market power mitigation and analysis of market structure in regional electricity markets. CEIC notes that measures of market structure based on market share were designed for use in industries where inventories are cheaply maintained and demand is elastic. Since electricity lacks either of these properties, CEIC proposes instead the use of a market structure metric based on the difference between the excess capacity of an ITP system and the generating capacity of firms within the system (similar to the pivotal supplier concept).

The mitigation measures proposed in the NOPR consist primarily of bid caps, mandatory offer requirements, an increased role for demand response, and resource adequacy requirements. The first two measures are problematic. The combination of mandatory sell requirements and price caps may amount to an unconstitutional “taking”. This is because the federal government would oblige a firm to sell a good at a fixed price that may not represent fair compensation for the firm. Such a mandatory offer requirement can only be made compatible with the takings clause of the Constitution if compensation is made on an average cost basis, a decision that brings FERC back to the regulation it purports to be ending.

Even demand response cannot be relied upon to mitigate the effects of market power. Moreover, the resource adequacy requirement also may not go far enough in some ITP systems.

Cinergy supports FERC's efforts to create and enhance competitive electric markets and believes that SMD is important in reaching this objective. Cinergy believes that 3 fundamental philosophies need to be at the root of SMD.

1. Making new markets work. Cinergy believes that, with modifications, SMD will accomplish this goal. Not all markets are at the same stage of development. SMD rules should allow limited recognition of regional variation.
2. Allowing market optimization. While Cinergy understands FERC's desire to place some controls on marketplace behavior, it is deeply concerned that such mitigation measures can interfere with price signals and prevent development of optimally efficient markets.
3. Investment and cost recovery mechanisms. FERC's goal of transitioning to a new market design cannot be realized without transition costs. As a transmission owner, Cinergy will incur costs in implementing SMD. Guaranteed full cost recovery is a critical component of SMD. Customers are the beneficiaries of SMD and should bear the costs, not shareholders. Cinergy asks FERC to confirm this, and to specify the means of cost recovery with respect to costs associated with taking service under the SMD Tariff on behalf of retail load, and the means of cost recovery in state with frozen retail service rates.

The Colorado Public Utilities Commission (COPUC) has an initial concern that the NOPR is incomplete. The NOPR presumes that undue discrimination exists, but does not in fact establish that this is the case. Further, the NOPR lacks sufficient detail for the states to properly comment. Other concerns are:

1. Jurisdiction.
   1.1. FERC lacks jurisdiction over the transmission portion of bundled retail services. COPUC cites §201 of the FPA and FERC's own arguments in *New York v. FERC* to support to support its contention. *New York v. FERC*, 122 S.Ct. 1012, 1033-35 (2002) (Thomas, J. concurring in part, dissenting in part) (pp. 4-7).
   1.2. Certain issues (e.g. generation planning & siting and resource adequacy) proposed to be addressed by RSACs are within the jurisdiction of states. FERC cannot regulate by proxy those areas where it lacks jurisdiction (pp.7-8).
   1.3. Similarly, FERC may not delegate to an ITP the authority for resource planning because FERC itself does not have such jurisdiction. This lack of jurisdiction is clearly stated in §201(b)(1) of the FPA (pp.8-9).
2. FERC Compliance w/ §206 of the FPA.
   2.1. FERC has not fulfilled the requirement of holding a hearing before making a finding of undue discrimination. This raises due process concerns (pp. 9-10).
   2.2. COPUC rebuts FERC's reliance on Order No. 888 and *New York v. FERC* as a basis of broad authority to determine whether undue discrimination exists (pp. 10-12).
      2.2.1. Crucial issues were not addressed in Order No. 888 or *New York v. FERC*.
      2.2.2. Order No. 888 dealt only with wholesale competition.
      2.2.3. The SMD NOPR presents no evidence of actual undue discrimination.
3. Policy Concerns.
   3.1. The sweeping changes in electricity regulation proposed in the NOPR will surely entail some unforeseen errors and consequences. FERC should be cautious about implementing such large-scale and untested measures (p. 13).
   3.2. FERC should not attempt to alter the time-tested structure of vertically integrated utilities, a structure chosen by Colorado, without specific findings. FERC should do a cost/benefit analysis and demonstrate that other actions would not be more appropriate (pp. 14-16).

The United States Department of Energy (DOE) offers comments on several specific issues related to SMD.

1. Incentives for Transmission Investments and the Need for Robust Forward Markets.
   1.1. LMP alone is unlikely to provide an adequate stimulant for new transmission investment. Further, LMP shows where additional transmission capacity is needed at present. Ideally, given the lead-time required to put such capacity in place, additional investments should be planned and built before LMP begins to flash its price signals in real time.
   1.2. Regional transmission planning will help identify additional transmission needs on a forward-looking basis, but developers need assurances from FERC and state commissioners that they will be able to recover costs. Developers of merchant transmission projects need similar assurances via long-term contracts with buyers or sellers of wholesale electricity. However, even with assurances from regulators, investments might continue to stagnate unless robust and transparent forward markets are developed for wholesale power at the regional level.
   1.3. DOE recommends that FERC hold workshops or technical conferences to explore the potential benefits of formation of regional forward markets.
2. The Need to Address Cost Allocation (Including Participant Funding) in Regional Planning and Review Processes.
   2.1. DOE believes that to the extent practical, costs should be allocated in proportion to benefits received. However, given the complexity of estimating net benefits to diverse parties, an either/or choice between participant funding and rolled-in pricing would be inappropriate as a general policy.
   2.2. DOE offers suggestions for the final SMD rule.
      2.2.1. Cost allocation should follow cost causation. Some projects, however, may warrant a blending of participant funding and rolled-in approaches.
      2.2.2. FERC should consider requiring ITPs to prepare project-specific proposals for allocating the costs of new non-merchant grid-enhancing projects. They should attempt to allocate costs in proportion to benefits to be received.
      2.2.3. The ITPs' cost-allocation proposals should be subject to review and affirmation by the affected states. Ideally, a regional MSE would be available to coordinate these reviews.
      2.2.4. For a given project, all affected governments should contribute to the design of the ITP's analysis.
3. DOE is concerned that creating an RSAC and an MSE in each region could increase costs and hider the effectiveness of each.
4. Demand Response and Wholesale Electricity Markets.
   4.1. DOE is concerned that much of the effort by RTOs and states to foster demand-response capability has focused on averting price spikes and other forms of market instability under near-emergency conditions. It suggests that the RTOs (or ITPs) and states broaden their focus to include programs to enhance customer ability to take economic advantage of the predicable daily and seasonal oscillations in wholesale electricity prices.
   4.2. DOE is interested in working with states and other interested parties in developing performance-based ratemaking plans.

Duke Energy Corporation (Duke) supports FERC's continued restructuring of wholesale electric markets, but cautions that an effective SMD must balance state and federal interests and allow for regional flexibility. Duke articulates six policy priorities for effective market design.

1. Nondiscriminatory Access. Duke strongly agrees that a tariff with a single form of transmission service, in conjunction with LMP and CRRs, and which provides for a single security constrained economic dispatch in which all wholesale suppliers can participate, provides the best platform for competitive wholesale markets.
2. Strong Market Monitoring. Duke strongly supports FERC's emphasis on market monitoring. However, it cautions that over-reliance on price mitigation will hinder the transition to competitive markets, subdue investment in infrastructure, and interfere with the ultimate goals of restoring market confidence. Duke urges FERC to remain focused on how best to prevent the exercise of market power through transparent liquid markets, meaningful demand response, prudent forward contracting, and construction of needed infrastructure.
3. Limited Regional Variation. Duke believes regional variation can and should be accommodated as long as it can be shown that the variation is needed to address specific circumstances, and provided that the accommodation of variation would not itself lead to unsolvable market inefficiencies. Moreover, the need for regional variation may require FERC to approve different timetables for SMD implementation in different regions.
4. Federal-State Cooperation. Duke understands the challenges facing both FERC and state regulators in defining their respective authorities. However, these complexities cannot be swept aside while the industry forges ahead on the technical issues of market design and tariff rules. Duke is concerned that certain aspects of the NOPR, such as resource adequacy requirements and regional planning, raise questions of federal-state jurisdiction. This may be unnecessary, as Duke believes that SMD can be developed in a manner that respects state jurisdictional interests.
5. Regulatory Certainty. For Duke, it is imperative to receive a clear signal from FERC on its regional intentions, for a changing landscape, coupled with significant and potentially unproductive expenditures resulting from such changes, creates an untenable position for the company.
6. Transition Mechanisms. FERC should adopt transitional measures that can be implemented quickly for regions where SMD will not be implemented in the near-term.

The Edison Electric Institute (EEI) generally supports FERC's efforts to develop a SMD, but believes many elements of the proposed rule need to be modified and require more flexibility. In particular, more flexibility is required with respect to regional differences, the timing of implementation, governance, planning, resource adequacy, and matters that do not directly relate to market operations. EEI comments extensively on the SMD NOPR. This summary focuses on some of the issues addressed that are of special concern to state regulators.

1. A framework for state participation must be assured. The SMD will affect important state interests but provides an insufficient framework for state participation. State jurisdiction over regional planning and resource adequacy exceeds that of FERC. The responsibilities imposed on utilities and state regulators by state statutes with respect to planning, adequacy, and siting must be respected.
2. EEI urges FERC to adopt of more flexible and realistic implementation timetable, particularly given the different stages of market and infrastructure development in different regions.
3. Section 9.1 of the NAS tariff could be interpreted as allowing ITPs to offer NAS Tariff service to any retail customer regardless of whether the state with jurisdiction over the retail service has adopted a retail choice program. FERC should not permit ITPs to be vehicles for the implementation of retail wheeling, unless authorized by state law.
4. EEI supports FERC's proposal to establish a SMD that includes a comprehensive spot market, including: LMP, a financial rights-based congestion management system, real time markets, and a day-ahead market with voluntary participation.
5. EEI agrees that each ITP should have a Market Monitor. The MM should provide its final reports to FERC, the Board of the ITP, the states, and market participants. To the extent that proprietary data is used, the MM should hold the information on a confidential basis. EEI recommends that FERC provide market participants with greater assurances that company specific information is protected from unauthorized use and disclosure. In addition, EEI believes that the MM should not be responsible for enforcing market rules. FERC cannot legally, and should not as a matter of policy, delegate its enforcement authority under the FPA to the MM or the ITP. FERC must provide for the equal enforcement of market rules and mitigation. This is particularly important in the West where non-public utilities are major market participants.
6. EEI supports FERC's approach in allowing NERC to continue to develop cyber security standards. However, while preparation of draft standards have been approved by the NERC Board, they have not yet been fully vetted by the industry and are likely to require some modifications. Appendix D of EEI's comments offers suggestions for modifications.

The comments of Edison Mission Energy and its subsidiaries (EME) strongly support FERC's efforts to implement competitive wholesale markets. However, they also register concern that FERC has combined two disparate subjects—planning/expansion of transmission and market design—that raise distinct issues and should be separately addressed. The features of the NOPR that relate to the structural design of competitive wholesale markets are soundly based, timely, and essential. There is no reason to delay their adoption pending the resolution of the highly contentious issues surrounding future transmission planning and expansion. These issues should be severed form the NOPR.

Exelon agrees with the concept of SMD and enthusiastically supports the core principle of having regional ITPs facilitate markets based on LMP.

1. Exelon supports a process in which the market monitor works with stakeholders to devise mitigation measures. It does not support a process in which the market monitor can effectively set prices or in which the market monitor has discretionary authority to impose penalties on market participants.
2. Exelon applauds the proposal to establish a single standard type of transmission service. However, it is seriously concerned that eliminating firm point-to-point service or its equivalent for interregional transactions would be premature. Financial congestion hedges will not take the place of physical rights for interregional transfers until there is seamless redispatch across all markets.
3. FERC's proposal for nodal LMP with CRRs provides the soundest form of market-based congestion management. Exelon strongly believes, however, that CRRs should not be fully funded.
4. The final rule should recognize that there is a need for ITCs with sufficient functionality to optimize the operation and expansion of the grid.

The Florida Public Service Commission (FPSC) voices several concerns with the SMD NOPR.

1 FPSC is concerned that FERC is placing bundled retail transmission service under its authority. Notes that this not only arguably exceeds FERC's jurisdiction, but also conflicts with the statutory obligations of FPSC to its native load. Suggests changing the SMD NOPR's proposed rule 35.35(a) to provide: "*Applicability: Upon a formal finding by the FERC that a public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce has engaged in undue discrimination unrelated to statutory obligations imposed on it by state law or rule, that public utility must comply with the requirement of this rule by* (date)." (pp. 6-8).

2 FPSC believes that FERC's attempt to regulate generational resource adequacy is an ultra vires act. The argument is that FERC is excluded from exerting jurisdiction over facilities used for the generation of electric energy or over facilities used in local jurisdiction by §201(b)(1) of the FPA. Proposed rule 35.27 of the NOPR would grant ITPs authority over such facilities. Therefore it recommends deleting the proposed rule 35.37 entirely. (pp. 10-12). Similarly, the FPSC believes that FERC cannot and should not assert any authority over demand response load. (pp. 12-14.)

3 Formation of RSACs is not the optimal mechanism to ensure state input. The FPSC believes that although some type of advisory role would be helpful to ITPs, a RSAC cannot be delegated any authority—nor can the ITP assume any authority—that is state jurisdictional with respect to generation and transmission planning without specific state legislative authority. Additionally, the FPSC suggests that there is another mechanism. FPA §209 provides that FERC has authority to refer matters to a joint board. Such a board could serve as a bridge between FERC and the states. (pp. 15-16).

4 The FPSC is also concerned that the NOPR emphasizes market design but does not fully develop methods for mitigating market power. Market monitoring and market power mitigation mechanisms should be in place before new markets are implemented. (p.17).

In general, the Georgia Public Service Commission (GPSC) is concerned about the necessity for the extensive changes proposed in the SMD. FERC has not demonstrated that such drastic changes are needed. There has also been no showing of undue discrimination by Georgia utilities, although this is one of the main reasons cited for the SMD. GPSC also doubts whether the SMD and the formation of the SeaTrans RTO will benefit consumers. The costs of implementation may outweigh any potential benefits, causing rates to increase. GPSC reminds FERC of the SEARUC Cost/Benefit Analysis and stresses that FERC needs to address such concerns before implementing a final rule. Moreover, the NOPR has FERC imposing jurisdiction on the transmission portion of bundled retail service that is now regulated by the states. Georgia, like a majority of the states, has not deregulated its electricity industry, and does not contemplate doing so if there are no benefits to be gained. FERC is urged to proceed slowly and to consider regional differences. Some specific areas of concern with the content of the NOPR are:

1. GPSC is concerned about the breaking up of Georgia's vertically integrated utilities by the formation of an RTO. This could result in additional costs to ratepayers. GPSC would like to see evidence that there is undue discrimination and that the SMD would be an adequate remedy (p. 5).
2. If CRRs are implemented, presumably the CRR holders would have scheduling priority. GPSC believes that native load should retain priority in scheduling of the use of available capacity during transmission system constraints (pp. 5-6).
3. GPSC questions whether FERC has the authority to assert jurisdiction over rates for bundled retail customers. If FERC does assert such jurisdiction, it should allow an optional transition period to protect bundled retail customers (p. 6).
4. There should not be a uniform cost allocation of inter-regional costs among all zones within an ITP's system because this would result in imposing costs through a region-wide charge on customers who do not import power. There does not appear to be merit in allowing the inter-regional transfers to be netted out between zones within neighbouring ITPs in a manner that assigns transmission costs to all customers within the import zone and returns the revenue to the export zone, if an acceptable method of assigning costs to zones that is not subject to manipulation or gaming could be developed (pp. 7-8).
5. GPSC supports the principle that the costs of transmission expansion be paid for by those who benefit from it. FERC indicates that it would allow participant funding for proposed transmission facilities that are included in a regional planning process that is conducted by an ISO or RTO. GPSC is concerned that these requirements would delay or impede the implementation of participant funding until these conditions are met. GPSC asks FERC to respect regional differences and recognize that participant funding is very important to the Southeast and the SeaTrans RTO (pp. 8-9).
6. GPSC asks FERC to also respect regional differences in regard to LMP. An adequate transition period for implementing LMP must be provided (pp. 9-10).
7. GPSC is uncertain of ways in which a market established to comply with the FERC proposed SMD could be manipulated (p. 10).
8. In order to deter gaming and market manipulation, it may be necessary to have a uniform safety net bid cap across the region. The idea of imposing a system of price regulation where caps of $1000 per MWH are deemed necessary sets off alarm bells.

The ability to keep the benefits of low cost, local generation resources with the state's retail ratepayers is a major concern. GPSC will not endorse a regulatory scheme that will lead to the state regulated electric utilities and their customers experiencing extended power outages or paying $1000 per MWH under a FERC tariff that could result in such costs being passed onto Georgia ratepayers (pp. 11-12).

9. GPSC favors allowing each region to select its own preferred method for determining bid caps from the three methods identified by FERC (p. 12-15).

The Iowa Utilities Board (IUB) believes that FERC's SMD has become a policy statement rather than a proposed rule that would be binding on all regions of the country.

1. The reasons for this belief include FERC's acceptance of non-conforming market structures for the Southeast and the West, as well as statements made by FERC commissioners that more regional flexibility will be allowed than contemplated in the NOPR. IUB suggests that FERC not require the SMD, but instead adopt a policy statement that would serve as a goal. There are many advantages of such a "policy" approach.
    1.1. A policy approach would avoid burdensome litigation.
    1.2. While the SMD proposal would lead to immediate construction of transmission facilities, it is difficult to see any other direct benefits to customers in bundled retail states.
    1.3. SMD as a policy would not mandate costly market changes by arbitrary deadlines.
    1.4. SMD as a policy allows useful regional variation.
    1.5. A policy approach would reduce the level of resistance to SMD, and thereby diminish the amount of uncertainty.
    1.6. By reducing market uncertainty, a policy approach would help create incentives for change.
2. IUB raises several jurisdictional issues.
    2.1. The evidence cited in the NOPR to support FERC's findings of discrimination may not be persuasive to many stakeholders. The findings appear to be based largely on anecdotal evidence and informal complaints. Moreover, no specific instances of an Iowa utility engaging in discriminatory practices are cited.
    2.2. Questions are also raised by FERC's assertion of jurisdiction over bundled retail transmission. IUB believes that a preference for native load is not undue discrimination. Priority for native load access is appropriate so long as it is not abused for such things as capturing market share. Iowa's state law requires utilities to serve their customers at reasonable costs. The transmission system was built to serve native load in Iowa. The instances cited by FERC may be nothing more than a utility complying with state law.
    2.3. IUB is also concerned with the basis for FERC's assertion of jurisdiction over generation resource adequacy and demand response load. Both of these are areas of traditional state jurisdiction. Furthermore, the FPA expressly reserves such jurisdiction for the states.

The Illinois Commerce Commission (ICC) generally supports the SMD NOPR. However, there are a number of areas in the NOPR that require clarification and, in some cases, changes to the SMD proposal.

1. FERC's step backwards form RTO implementation agendas will likely be counterproductive. Rather than pursue the ITP approach introduced in the NOPR as an interim step, ICC urges FERC to continue to move toward prompt and full participation by transmission-owning utilities in properly designed and properly configured RTOs (pp. 7-9).
2. Addressing the role of ITCs within an RTO/ITP framework and SMD continues to be difficult because there is no single commonly accepted definition of what constitutes an ITC (pp. 9-12).
3. The success of market monitoring and market power mitigation depends on the independence of the Market Monitor (MM) from both the ITP and market participants. However, the framework established by FERC in Order 2000 (largely retained in the SMD NOPR) makes it very unlikely that the MM will be independent (pp. 15-17).
   - 3.1. All information collected by the MM should be made available to the state commissioners, provided that confidential information is protected (pp. 17-18).
   - 3.2. The MM should be able to implement an automatic mitigation procedure in any of the markets it oversees (pp. 20-21).
   - 3.3. ICC is concerned that the MM penalty authority is not clear (pp. 21-22).
4. RTO/ITP Governance (pp. 22-24).
   - 4.1. ICC believes that the NOPR's restrictions with respect to Board member selection, Board member replacement, and Board member terms may stifle legitimate creativity in these RTO/ITP governance elements.
   - 4.2. The NOPR's proposal to create a subset of stakeholders in the form of a nominating committee to select the RTO Board is flawed.
5. ICC urges FERC to maintain its long-standing policy of deference to the states on liability limitations with respect to third parties (pp. 26-29).
6. While ICC supports FERC's goal of eliminating undue discrimination in interstate transmission service, FERC's efforts must complement and not undermine or conflict with Illinois' retail competition program (pp. 29-32).

The Indiana Utility Regulatory Commission (INURC) submits comments concerning congestion management and day-ahead and real-time markets. The proposed new transmission system requires successful introduction of LMP in markets. However, the introduction of the SMD in a large, multiple control market area, one without a tradition of tight power pools, will need some extra attention to assure the integrity and successful implementation of the wholesale power market redesign.

1. INURC agrees with FERC that the use of LMP seems to be the only way to develop a regional competitive wholesale market. It outlines several elements necessary for sound market design.
   1.1. Forward bilateral trades and self-scheduling of generation will be the primary basis for load serving entities to meet their load. If too much emphasis is placed on the day-ahead and real-time spot markets, without allowing for forward bilateral trades, transmission customers will not be able to manage risk associated with exposure to price volatility (p. 4).
   1.2. INURC agrees with FERC that the ITP must operate a security-constrained, financially binding day-ahead energy market that is operated together with a day-ahead scheduling process for transmission service. Traders should be allowed to do purely financial bids. However, in the real-time market, they should be held responsible for any physical obligations (p. 5).
   1.3. Although CRR comments are due later, some parts are so closely related to the congestion management system that highlighting the main characteristics is appropriate at this time. INURC wants to highlight that CRRs in the LMP model should be financial and not physical (p. 5).
   1.4. INURC agrees that the use of marginal losses follows from the same principles as any other marginal cost. It does not support, however, the suggestion to use average losses because this might be simpler (pp. 6-7).
   1.5. FERC should avoid being overly prescriptive in requiring ex post versus ex ante pricing or in specifying the details of ex post pricing. The SMD NOPR appears to favor an ex post pricing approach, primarily to encourage generators to operate in a manner consistent with their bids and the ITP's dispatch instructions. ITPs should be allowed flexibility to use either method, particularly during a transition when existing software limitations may dictate the answer (pp. 7-8).
2. Of secondary importance, it will be important to develop different CRR products but INURC believes that initially only obligations should be offered. The introduction of options and flowgate rights will increase the volume of possible combinations and will become too computationally burdensome to be implemented in a new market. Additionally, ITPs should only offer pre-day-ahead markets for energy and ancillary services after the market has been in operation for a while.

The joint comments of the North American RTOs and ISOs (joint comments) first identify those key areas where they support FERC's proposals; then point out areas where FERC should either clarify or modify aspects of the NOPR.

1. Aspects of the NOPR supported by the joint comments.
   1.1. SMD should be implemented.
   1.2. The utilization of NAS is appropriate under LMP.
   1.3. FERC is correct to allow flexibility in the development of a rate design for the recovery of the fixed charge component of transmission charges.
   1.4. The joint comments recognize the need for independence of the ITP.
   1.5. The joint comments support explicit acknowledgement of security requirements.
2. Areas where FERC should either clarify or modify the NOPR.
   2.1. The role of states and the RSAC.
      2.1.1. FERC should clarify that the establishment of a RSAC is intended largely to formalize the "best practice" processes in place today in many ISOs by which the states engage in dialogue with the independent entity that will operate the electric grid under SMD. Formalizing the RSAC would have many benefits. The states have a significant interest in the operation of electric markets because of their authority over retail ratemaking. State entities that participate in the RSAC, therefore, should serve as advisors to the ITP, which makes the decisions.
      2.1.2. FERC needs to clarify its intent as to whether the RSAC would be truly "advisory" or would have some greater decision making role. In areas clearly within its jurisdiction, FERC should avoid suggesting that the RSAC has separate legal authority.
   2.2. The role of NERC and NAESB.
      2.2.1. While RTOs and ISOs expect to continue their individual participation within NERC and the Regional Councils, they are also discussing with NERC the establishment of an additional forum for providing their collective input to NERC via an MOU.
      2.2.2. FERC needs to clarify its statement that NAESB would work closely with ITPs who would collectively serve in an advisory capacity to the board of NAESB. NAESB is to be run by stakeholders who have a direct business interest in the standards to be developed.
   2.3. The role and structure of the entity or staff conducting market monitoring should be clarified.
   2.4. FERC should recognize regional differences and the need for flexibility with respect to implementation timelines.
      2.4.1. Changes in market design will require a transition period. Many of the RTOs and ISOs have operating markets that vary in the extent to which they are similar to SMD. These markets should continue to operate without interruption during the transition period.
      2.4.2. FERC should recognize variations in the ancillary services markets.
      2.4.3. Regions that have developed an approach to grandfathered contracts should be allowed to keep that approach.
      2.4.4. FERC should not require a reallocation of previously allocated CRRs.

2.4.5. Mitigation measures should vary by region.

2.5. There is a need for software modularity. It is important in mandating standards not to stifle innovation.

2.6. Explicit limitations of ITP liability should be included in the pro forma tariff. The limitation of liability would protect the ITP from liability for any damages, except to the extent the ITP is found liable for gross negligence or intentional misconduct. Without regard to the standard of care, the tariff should also make clear that the ITP is not liable, under an circumstances, for any special, indirect, incidental, consequential, or punitive damages.

2.7. Where ITCs are developed, the ITP must be the single operational authority under an SMD model. The overall operational authority and the congestion pricing methodology under the SMD regime should reside only at the ITP, not in an ITC. This needs to be clarified.

The Kentucky Public Service Commission (KPSC) has serious concerns regarding the jurisdictional implications of the SMD NOPR, as well as the adverse consequences for Kentucky's electricity ratepayers if the rules as proposed are adopted.

1. The SMD NOPR, intended to provide financial stability to electricity markets, will destabilize retail markets in rate-regulated states such as Kentucky. Kentucky has used the contract method for decades to ensure that adequate electricity production and transmission capability are available. Long-term contracts mitigate against the boom and bust cycles that characterize an unregulated energy market (pp. 6-8).
2. Though the KPSC recognizes the importance of creating certainty and stability, the SMD NOPR does not achieve those goals. The SMD NOPR is an overreaction to the financial devastation that has recently occurred in some electricity markets. The proposed rule would not only penalize those portion of the nation that do not suffer from the problems that gave rise to the NOPR; they would not even restore financial stability to the areas that have suffered. Rather than rush to judgment, FERC should address individual markets and their problems (pp. 8-9).
3. The NOPR would unfairly burden Kentucky's retail ratepayers with costs properly borne by those who will benefit from SMD implementation. First, administrative costs are likely to increase. Few of the costs involved with an RTO are incurred for the benefit of retail load since the functions performed neither enhance service reliability nor lower the cost of service to bundled retail customers. Additionally, the principle of cost causation demands that the costs of developing a robust wholesale market be borne by the participants in the wholesale market, not by bundled retail ratepayers. This principle is also applicable to the issue of transmission expansions and upgrades. These projects must be participant funded. This issue will be more fully developed in subsequent comments to be filed in January 2003 (pp. 9-13).
4. Absent a thorough cost benefit analysis demonstrating benefits to all, FERC should not implement SMD. KPSC can only assume from the absence of evidence in the NOPR that FERC has conducted no such analysis. It fully support language added to the House Appropriations bill in September 2002 that would require DOE to conduct a cost study of the SMD prior to implementation of the rule (pp. 13-14).
5. The new congestion management system will be costly to implement, and may not preserve the vested rights of those who have paid for the existing systems. KPSC has several concerns; foremost is the cost. Significant work is required to convert existing firm transmission service into its equivalent under LMP (pp. 14-16).
6. Those who have paid the embedded cost of transmission should retain the right to use all of that transmission capacity (pp. 16-17).
7. FERC's proposal for a federally mandated generation requirement is not only unlawful, it is bad regulatory policy, and it should be removed from the SMD NOPR. Specifying an arbitrary requirement is inferior to the more flexible approach taken in Kentucky, where each utility's resource plans are periodically reviewed with a more in-depth process for each individual project (pp. 17-18).
8. The NOPR would relegate the states to merely advisory roles, interfering with their exercise of the police power and depriving the general public of a meaningful voice. The purpose and powers of the RSAC are not sufficiently spelled out in the NOPR. It appears that the RSAC may infringe upon, or even supplant, state authority over a

number of functions, including resource adequacy, transmission planning and expansion, rate design and revenue requirements, demand response and load management. To the extent that FERC intends the RSAC to supplant or diminish state authority over these functions, KPSC is adamantly opposed to the RSAC. A related concept that may merit more attention is that of Multi-State Entities (MSE). Further comments regarding RSAC and MSE will be filed in January 2003 (pp. 18-20).

9. Any market monitoring mechanism must provide the monitor with meaningful authority, ensure independence, and actively involve state regulators. The market monitor must (1) be independent, (2) play an active role in the market design and planning process, (3) be given the necessary resources, such as access to real time data, (4) must be able to impose after the fact penalties, and (5) must report directly to state regulators. (pp. 20-21).
10. FERC lacks the jurisdiction to implement large segments of the SMD NOPR. In *New York v. FERC*, the Supreme Court did not hold that FERC has jurisdiction over the transmission component of bundled retail sales. Nevertheless, it is upon this opinion that FERC has asserted the power, under §206 of the FPA. FERC has made two additional errors in its broad assumption of jurisdiction in the NOPR: (1) it failed to take into account explicit limitations on its jurisdiction in other sections of the FPA, and (2) it wholly ignores the logical impossibility of finding utility discrimination against retail competitors in areas where there is, by law, no retail competition (pp. 21-24).

The Louisiana Public Service Commission (LPSC) concludes that the SMD NOPR should be withdrawn at this time in its entirety. [There are no page numbers in the original document.]

1. The LPSC Has a Constitutional Duty To Maintain Reliable Electric Service in Louisiana at the Lowest Reasonable Cost.
   1.1. The LPSC is vested with the jurisdiction and authority over the rates and services of Louisiana utilities by the Louisiana Constitution. The LPSC cannot consent to the SMD because it seeks to take away the jurisdiction that the LPSC has, and needs, to continue to provide Louisiana customers with reliable service at the lowest reasonable rates.
2. FERC Has No Jurisdiction Over Bundled Retail Service and Cannot Force RTO Participation.
   2.1. The FPA preserves state jurisdiction over all retail ratemaking issues. The U.S. Supreme Court has confirmed the limited preemptive effect of the FPA. It held that that the FPA "had no purpose or effect to cut down state power", rather "perhaps its primary purpose was to aid in making state regulation effective." *Panhandle Eastern Pipe Line Co. v. Public Service Comm'n of Indiana*, 332 U.S. 507, 517 (1947).
   2.2. The LPSC's jurisdiction to set bundled retail transmission rates and to approve any RTO participation also is not preempted by the FPA. Sections 205 and 206 of the FPA give FERC some power to remedy discriminatory practices, but do not grant FERC the authority to require all utilities to transfer control of their transmission assets or to transfer system operating responsibilities to an RTO. Section 202(a) provides for the creation of regional districts for the "voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy…" However, this provision does not allow FERC to unilaterally configure and mandate participation in RTOs. Section 202(a) requires state participation and in no manner preempts state jurisdiction over nay transfer of ownership or control that could impact retail rates and service. Further, §202 does not give FERC any authority to usurp state regulation over planning and siting decisions.
3. Recent Studies Show That Louisiana Consumers Will Not Benefit From a SMD or Participation in RTOs Except for Benefits that May Arise From Participant Funding.
   3.1. The initial results of studies by SEARUC and by Entergy and SWEPCO demonstrate no real benefit, and the possibility of harm, for Louisiana and Southeastern customers.
   3.2. There is no evidence the SMD or RTO participation will benefit consumers in Louisiana or the Southeast.
4. Preferences Designed to Protect Native Load Customers and Fulfill State Regulatory Requirements Are Not Unduly Discriminatory.
   4.1. Not all preferences violate the FPA. To exercise its authority under §206, FERC must find more than the mere existence of discrimination or preferential practices. It must also find the discrimination or preference is undue.
   4.2. It is not undue discrimination for a utility to favor its own retail load in order to satisfy state law obligations.

4.3. FERC finds that market participants are discriminated against unduly if they cannot gain access on an equal basis to compete with vertically integrated utilities that serve retail customers. That such market participants are not on par with vertically integrated utilities to serve retail load is precisely what Louisiana regulatory policy demands.

5. The “Evidence” Referred to in the NOPR to Support a Finding of Undue Discrimination Consists Principally of Undocumented Claims and Theoretical “Problems” That, If They Exist at All, Can Be Addressed Without Need of the Sweeping Reforms Proposed by the Rule.
   5.1. Section III of the NOPR lists categories of actions that are alleged to constitute undue discrimination in the practices of transmission providers. The problems are said to be based on “allegations, formal complaints, hotline calls, public conferences and pleadings,” but little or no detailed or formal documentation is provided.
      5.1.1. Load growth. Meeting load growth is a requirement of a utility’s operation under well-founded state law. The remedy for disputes concerning reservations for future growth in native load is clear: enforce the existing pro forma tariff requirements for recall identification.
      5.1.2. Delays in responding to requests for service. The LSPC instituted a docket to examine problems related to generator interconnection and queue length over two years ago. Since that time the problems alleged by the merchant generators have been addressed, and the waiting time for interconnection studies has decreased dramatically. The issue for FERC lies with enforcing industry-wide rules, not usurping state jurisdiction and mandating RTO participation.
      5.1.3. Scheduling advantages in a large portfolio of generators and loads are an economic fact. This is why a majority of states have chosen not to unbundled utility service.
      5.1.4. Imbalance resolution. A utility using its own state-jurisdictional generation resources to balance its own retail loads is not practicing undue discrimination.
      5.1.5. It is the position of the LPSC that use of capacity margins to increase retail reliability is not undue discrimination. Preservation of the native load exemption in ATC calculations is appropriate.
      5.1.6. OASIS postings. If FERC is unable to police violations of its existing regulations regarding OASIS operation, it is difficult to believe that it will be able to monitor and police all potential market abuses in the context of SMD.

6. ITCs Should Not Be Allowed Because They Injure Retail Ratepayers, Provide No Competitive Benefits and Require State Approval.
   6.1. There is no evidence that there will be any benefits to retail ratepayers or the industry in the ITC structure. In fact, use of ITCs will inflict significant harm on retail ratepayers and will not enhance wholesale competitive markets.
   6.2. The LPSC has examined the proposed ITC structure in a retail docket. It determined that the transfer of ownership or control of transmission assets to an ITC is presumptively not in the public interest. This decision was based on factual findings.

7. Participant Funding Should Be Approved Without Restriction.
    7.1. Participant funding is necessary to prevent significant harm to retail ratepayers and is necessary to send appropriate cost signals to merchant generators to site the plants in the most effective manner.
    7.2. In the absence of participant funding, it appears that RTO participation will be economically harmful to the entire Southeast. Virtually all the benefits of RTO participation stem solely form assumptions regarding participant funding and merchant plant development.
    7.3. FERC has exceeded its authority because it seeks to make participant funding available, only if state regulators relinquish jurisdiction over transmission planning and investment.
8. The SMD Proposal On LMP Should Be Rejected.
    8.1. The LMP system has simple, theoretical appeal as a means to deal with congestion. This method has many troubling aspects, however, and may threaten much higher electricity costs.
        8.1.1. LMP may increase overall costs. The market for electric sales is not perfectly competitive and likely never will be. Paying all sellers the highest bid price that is accepted will increase prices relative to a system in which sellers receive what they bid. Utilities still would recover only their cost for regulated generating units, as price increments would offset added costs, but for purchases made by the utility, the overall impact of LMP could be substantial. It is unclear how ratepayers would be protected from these impacts.
        8.1.2. The LMP method contemplates price transparency. To the extent supply is short relative to demand, these sellers may use the information to coordinate prices, which would drive up prices. Even in the absence of supply shortages, such price awareness may promote coordination and supra-normal prices.
        8.1.3. The CRR system is meant to protect ratepayers from added costs imposed for transmission congestion. Yet ratepayers are vulnerable to the danger that the ratepayer protections will be inadequate or nonexistent. Further, the distribution of congestion costs to holders of CRRs may lead to significant cost transfers.
        8.1.4. A key objective of LMP should be to produce incentives to expand transmission and place generators in geographic areas that will relieve congestion, but the efficacy of this pricing scheme is unproven. If the added cost of transmission is offset by CRRs, it is unclear how those costs will promote desirable conduct.

The Minnesota Department of Commerce (MDOC) considers FERC's SMD NOPR to provide a good underlying basis for developing a standardized wholesale market design. MDOC raises some specific concerns regarding state versus federal jurisdiction and necessary assurances related to transmission rights and costs assignments for native load bundled customers.

1. Minnesota Background
   1.1. MN has chosen not to restructure the electric industry (p. 4).
   1.2. MDOC has raised serious concerns regarding costs assignments to retail native load customers and regarding retail native load customers' rights (p. 5).
   1.3. MDOC is concerned that FERC is trying to significantly change policy decisions and assert authority over bundled retail transmission. MDOC does not consider FERC's limited citations of a few alleged discrimination cases to support the efforts to assert "blanket authority" over the jurisdiction of bundled retail transmission. MDOC's primary concern in this regard is the effect of sweeping changes that appear to be envisioned mainly for open-access areas on native load bundled customers. FERC is urged to require services to be further unbundled and costs to be assigned to those who use the service, cause the cost, or benefit from the market being created or transmission rights being made available (pp. 5-7).
2. Comments on "Need for Reform" Section of NOPR
   2.1. MDOC supports requiring the RTO to calculate the ATC, with help from LSEs to make sure all data is correct. However, it is concerned about FERC requiring the RTO to perform facilities studies, since this may result in backlogs. It may be more practical to require the RTO to have oversight authority and work on managing the queue process. The RTO would assign the facilities studies to the LSEs to do (p. 7).
   2.2. MDOC supports OASIS postings (p. 8).
   2.3. MDOC supports FERC's remedy of using LMP to manage congestion as long as this approach does not reduce reliability to native load customers or shift costs inappropriately to these customers (p. 8).
3. Comments on the "Proposed Remedy" Section
   3.1. MDOC is concerned about the comment at ¶108 of the NOPR, "[t]he current regulatory system allows vertically integrated utilities to discriminate in favor of their bundled retail load at the expense of wholesale customers." The existing transmission system was built for bundled retail load customers long before there were any wholesale customers. Moreover, bundled retail load customers have few alternatives to taking service from their LSE. Thus, bundled retail load customers should have preference (p. 9).
   3.2. It is not clear what the pros and cons are to removing the distinction between network and point-to-point service, since these were not discussed in the NOPR (p. 9).
   3.3. MDOC is concerned that CRRs or auction revenue may not match existing transmission rights or provide appropriate revenue to offset additional costs that will be incurred by retail customers as a result of allowing some users of the system not to pay an access charge and create free riders on the system (p. 10).

3.4. MDOC understands that affording continuing opportunity to existing customers to rollover or renew contracts is fair and reasonable. However, expecting existing customers to agree to a contract tern at least equal to a competing request ignores the possibility of speculative activities by power marketers and wholesale power traders with a potential to drive up transmission prices to the detriment of LSEs and retail customers (pp. 10-11).

3.5. An ITP with the proper scope and configuration is essential to provide nondiscriminatory transmission access at just and reasonable prices. Yet, it is critical to require the ITP to have significant market operation responsibility to make it difficult for individual entities to form an ITP that would give the impression that there is not total independence from parent companies (pp. 11-12).

3.6. MDOC is skeptical of the benefits to be derived from ITCs. Under no conditions does MDOC support allowing for-profit ITPs or ITCs to perform the currently defined ITP functions. The operation of the interstate transmission grid is too important to be subjected to profit driven motives (p. 12).

3.7. MDOC supports the requirement of an independent entity to oversee transmission service, but is concerned about duplication of transmission services at the LSE and RTO level, which will increase costs with no benefit (p. 13).

3.8. MDOC will provide further detailed comments concerning the new transmission service in its January comments (pp. 14-15).

3.9. MDOC supports LMP in theory, but would like to see actual prices and the final model before reaching a conclusion. It continues to be concerned about the success of a market that is operating with transmission constraints. Furthermore, MDOC would like to see further modeling of CRRs to ensure that retail native bundled load customers are not harmed by being required to pay additional costs for the same service they receive today (p. 16).

3.10. MDOC supports the day-ahead and real-time market. It stresses that LSEs are still required under state law to serve native load retail customers with existing low cost generation and bilateral contracts, using the lowest cost available method (p. 16).

3.11. MDOC generally agrees with FERC's CBM efforts. However, taking away CBM and offering it for sale by ITPs to all, and explicitly charging for it does not seem advisable (p. 17).

3.12. Market monitoring and mitigation are the most important issues of SMD to ensure that the electricity market is efficient and can deliver its objectives. MDOC has discussed this area in a joint state comment.

3.12.1. Penalties for unjustified forced outages should be sufficient to deter market participants from thinking that it may be in their financial interests to have an unforced outage (p. 20).

3.12.2. MDOC strongly recommends that mitigation triggered by market conditions be mandatory (p. 20).

3.13. MDOC is concerned that FERC's list of minimum committees could lead to a merger of consumer advocates and environmental groups. MDOC supports the separation of these groups as is currently done at the MISO level (p. 21).

3.14. FERC's approach to ensuring system security compliance through the implementation of Appendix G appears to need more refinement. In particular, it is hard to imagine organizations professing non-compliance on their own. In addition, it would be important to work with local agencies if emergencies arise (p. 21).

3.15. MDOC believes that the implementation guidelines are unrealistic. MDOC urges a phased in approach to ensure correct implementation (p. 22).

The initial comments of the Missouri Public Service Commission (MPSC) focus on several major areas.

1. Recommendations Regarding Federal-State Jurisdiction. State regulatory commissions have jurisdiction over the setting of retail rates for those utilities that are subject to retail rate regulation by state statute. It is of grave concern to the MPSC that in this NOPR FERC is requiring bundled retail load to be served under a regional transmission tariff that should have been designed for the purpose of facilitating wholesale transactions of electricity. The foundational principle with respect to transmission facilities used to serve bundled retail native load customers is that these customers should pay their share of the costs for the transmission facilities build by the utility providing retail electric service to them, and to the extent that the utility uses the transmission facilities of other transmission providers to serve its bundled retail load customers, these customers should pay their share of those costs as well. When the vertically integrated utility is directly providing transmission service to its own bundled retail customers, the cost of providing that transmission service comes under state jurisdiction. Only by following this major guideline will FERC avoid conflicts over state vs. federal jurisdiction (pp. 3-7).
2. Public Policy Recommendations Regarding Transmission Used to Serve Bundled Retail Load. The foundational principle that should drive public policy is that the internal load customers that provide the base for the utility to reasonably finance the building of transmission facilities should have first priority to the transmission rights on the transmission facilities that were built to serve them. Transmission access charges can easily be addressed by state regulatory commissions retaining and exercising jurisdiction over the determination of transmission costs in rates for bundled retail load. However, if FERC successfully asserts such jurisdiction, then in order to address this condition, FERC should apply the same benefits-driven transmission pricing policy for access charges as it contemplates for pricing inter-regional transactions and new transmission capacity. Additionally, when the utility has already built sufficient transmission to serve growth for internal load, it should receive protection form congestion charges not only in the present, but also in the future growth in that internal load. By using revenue from the sale of CRRs to reduce the revenue requirements for transmission access charges, FERC can achieve a benefits-driven pricing policy for both existing and new transmission, and this transmission pricing policy will remove major barriers to transmission expansion (pp. 7-25).
3. Recommendations Regarding the Structure of Day-Ahead and Real-Time Markets. These highly structured spot markets are needed to increase the overall efficiency for trading incremental energy and to provide the basis for liquid futures markets in electricity. FERC should allocate CRRs in zones that are paying transmission access charges in each of those zones. CRRs should be allocated to interior load customers as a first priority, and customers desiring “through” and “out” transactions on the basis of willingness to pay for the transmission on a long-term basis. Any excess CRRs that occur from year-to-year would then be sold at auction on a short-term basis.

- 3.1. Congestion Management. MPSC wishes to comment on what it considers to be minor flaws in the system of congestion management based on LMP and CRRs.
    - 3.1.1. Contingency CRRs for Intermittent Resources (p. 26).
    - 3.1.2. Use of CRRs to Provide Curtailment Priority (pp. 26-28).
    - 3.1.3. Limiting Flowgate CRRs to Only Options (pp. 28-29).
    - 3.1.4. Assignment of Revenue Shortfalls for CRR Payments (pp. 29-30).
- 3.2. Day-Ahead and Real-Time Market Services.
    - 3.2.1. Scheduling of All Requests to Pay Transmission Usage Charges (pp. 31-32).
    - 3.2.2. Scheduling Ahead for a Longer Period of Time to Save on Administrative Costs (p. 32).
    - 3.2.3. One-Stop Shopping Across ITPs' Borders (pp. 32-34).
    - 3.2.4. Marginal vs. Average Losses (p. 34).
    - 3.2.5. Allowing for Self-Provision of Losses (p. 35).
    - 3.2.6. Scheduling of Intermittent Resources (pp. 35-36).
    - 3.2.7. Extras Incentives for Demand-Side Bidding (pp. 36-37).
    - 3.2.8. Giving CRRs to Generators that Create Added Transfer Capability (pp. 37-38).
    - 3.2.9. Allocation of Costs for Ancillary Service Requirements (pp. 38-39).
    - 3.2.10. Charging for Ancillary Services (p. 39).
    - 3.2.11. Charging for Costs Associated with Replacement Reserves (pp. 39-40).
    - 3.2.12. The Application of Ex-Post vs. Ex-Ante Real-Time Prices for Settlements (p. 40).
    - 3.2.13. Additional Charges of Uninstructed Deviations (pp. 40-42).
    - 3.2.14. The Use of Bids from Lumpy Generators in Setting LMP (pp. 42-44).

4. Recommendations Regarding Structure of Long-Term Resource Adequacy Requirement. Due to the potential threat to the operational reliability of the transmission system, it is reasonable for FERC to propose and enforce the need for a resource adequacy requirement. The resource adequacy requirement should be entirely driven by operational reliability criteria and, therefore, should be determined by the ITP. The determination of whether or not each LSE meets its share of the resource adequacy requirement should be determined on an after the fact basis, there should be a dollar per megawatt penalty for being short of resources and that penalty should be designed to provide sufficient incentive for load-serving entities to meet the resource adequacy requirement (pp. 45-58).

The National Rural Electric Cooperative Association (NRECA) supports the overall goal of the NOPR. However, it believes that critical adjustments must be made. Several key issues were also missed by the NOPR. Such key issues include the obviously inadvertent, yet nevertheless implied, conversion of approximately 200 small distribution cooperatives into FERC jurisdictional public entities, notwithstanding that those cooperatives provide only bundled retail service to their consumer-owners. To address problems with the proposed rule, NRECA recommends that FERC narrow the scope of the NOPR and refocus it. The NOPR should focus on creating the necessary foundation for a competitive wholesale market and on protecting end-users from market failures and abuses. FERC should not take the next steps—to mandate the markets themselves—until the foundation has been laid.

The North Carolina Utility Commission (NCUC) concludes that FERC should refrain from implementing SMD at this time. Instead, it should identify any genuine instances of discrimination in wholesale markets and develop remedies for such problems that do exist which do not unlawfully invade the jurisdiction of state regulators or impose a risk of additional costs to North Carolina customers.

1. FERC lacks the authority to implement its proposed network access service and SMD.
   1.1. FERC does not have jurisdiction over the transmission component of bundled retail service and rates (pp. 15-18; 19-32; 32-41).
   1.2. FERC does not have jurisdiction to compel the independent operation of transmission facilities. It is well settled that §202 of the FPA does not provide FERC with any substantive powers to compel any particular interconnection or technique of coordination. *Duke Power Co. v. FERC*, 401 F.2d 930, 943 (D.C. Cir. 1968). Given the expressly voluntary nature of coordination under §202(a) of the FPA, FERC cannot mandate the adoption of a coordination agreement. *Central Iowa Power Coop. v. FERC*, 606 F.2d 1156, 1167-68 (D.C. Circ. 1979). Therefore, FERC cannot compel a utility to join an RTO, if such membership involves coordination with another entity (pp. 41-43). Moreover, even if FERC otherwise had authority to require divestiture in order to become an ITP, it is prohibited from doing so by §§212(g) and (h) (pp. 43-45).
   1.3. FERC interprets the Supreme Court's opinion in *New York v. FERC* to mean that it can conclude that the operation of a vertically integrated utility, in accordance with its state law obligations, the Order No. 888 pro forma tariff, and relevant federal law, constitutes undue discrimination and an "impediment to competition" that can be remedied pursuant to §206. A finding of undue discrimination, however, cannot be based on the existence and continuation of vertical integration, and §206 cannot be used to eliminate structural "impediments to competition" (pp. 15-18; pp. 45-61).
   1.4. The information in the NOPR does not support a finding of systemic discrimination sufficient to permit implementation of a massive multi-part generic remedy such as that proposed in the NOPR (pp. 61-66).
   1.5. The extent of FERC's jurisdiction over generation is too limited to encompass the dispatch and redispatch requirements of the NOPR. Section 201(b)(1) expressly provides that FERC shall not have jurisdiction over facilities used for the generation of electric power (pp. 66-67).
   1.6. The SMD proposed in the NOPR does not provide for the establishment of just and reasonable rates as required by §205 of the FPA. A mere assumption of competition of the type characteristic of the NOPR, without factual findings, is not sufficient to justify market pricing (67-69).
2. FERC should not implement SMD for policy reasons. The assumptions underlying the NOPR are either erroneous or insufficient to support the remedy proposed. The examples of discriminatory conduct cited do not amount to discriminatory conduct. For example, vertical integration should be deemed a proper state policy decision rather than something to be undermined by federal administrative fiat. In addition, with respect to the assertion that SMD is needed to cure current uncertainty and loss

of confidence in power generation markets, FERC should consider the inconsistency between those factors and the major thrust of the SMD. Current uncertainty and lack of confidence have not resulted from the continuation of vertical integration. Rather, the trading, market manipulation, and accounting scandals have shocked the industry. For the most part, these issues cannot be resolved by SMD. Finally, protecting vital infrastructure must be a major concern. Industry literature following the terrorist attacks of September 2001 recommended against further centralization of electric transmission. The DOE's *National Transmission Grid Study* suggests a series of smaller interconnections that are electrically independent of one another with DC links between them. This appears to be in direct conflict with FERC's desire for four large RTOs (pp. 68-78).

3. Regional differences dictate that the SMD not be imposed nationwide. Despite FERC's vision of a seamless national grid, a proper consideration of significant regional differences in the structure of the electric utility industry suggest that the SMD should not be imposed on all regions of the country at this time (pp. 78-82).
4. Specific aspects of the SMD proposal are too vague for effective comments to be provided necessitating further opportunity for comment. In many respects, the NOPR is no more than an elaborate, extremely complicated conceptual proposal. It is extremely difficult to effectively comment on many fundamental details that will be integral parts of the SMD. In addition to the legal issues raised by the inadequacy of the NOPR, changes as dramatic as the ones proposed must be more carefully defined and explained before the parties to this proceeding and the public can provide comments and raise concerns. For these reasons, FERC should withdraw the current proposal (pp. 82-83).

The North Dakota Public Service Commission (NDPSC) remains concerned with the impacts of transmission pricing on the economy of the state. It requests that FERC establish a schedule for implementing postage stamp or hybrid postage stamp pricing throughout MISO (pp. 2-3). Due to the immensity of the task, it may be prudent to phase in SMD (p. 4). NDPSC urges FERC to weigh the positive benefits of speculation against the risk of decreased reliability in the spot market. What happens if more energy is sold in the day-ahead market than is available in real time? (pp. 4-5). NDPSC believes that distinguishing between transmission and distribution lines should continue to be done according to function. A bright line voltage requirement should not be adopted because facilities operating at the same voltage can often perform different functions (p. 5). NDPSC comments that if preferences for native load are to be removed from the tariffs of jurisdictional utilities, then such preferences should also be removed from non-jurisdictional utilities as well. This is not to say that NDPSC agrees with eliminating preferences for bundled native load, but developing fair and robust competition requires a level playing field (p. 6). NDPSC applauds FERC for proposing a safety net bid cap. It cautions, however, that a bid cap has the potential to greatly affect consumers. NDPSC suggests setting the safety net bid cap equal to the incremental startup and running costs of the most expensive generator plus a reasonable margin of profit (pp. 6-7).

The New Mexico Public Regulation Commission (NMPRC) believes that FERC should withdraw the SMD NOPR and make substantial modifications to allow for regional approaches. Such modifications must be made with meaningful input from state commissions. There is also a need for credible cost benefit analysis of RTOs and SMD. The NOPR proposes to make fundamental changes in electricity transmission. Those changes appear to be mandatory, and to necessitate significant changes in the jurisdiction of state commissions. NMPRC believes that the FPA does not contemplate such radical jurisdictional shifts. It is axiomatic that the authority granted to FERC under the FPA involves the regulation of wholesale electric power and transmission, and does not authorize FERC to unilaterally require state commissions to conform to a new regulatory model that has widespread implications for retail rates. The assertion of FERC jurisdiction over major elements of retail electricity service amounts to a transfer of authority from the state commission to FERC. This would entail of loss of control over, *inter alia*, demand forecasting, resource planning, demand-side management and marketing, and the ability to ensure that transmission is available to meet retail service obligations. Moreover, such vast changes would effectively remove the business of electricity transmission from any meaningful public scrutiny or accountability. The state commissions are intrinsically more accessible to the public than FERC. No meaningful accountability is built into the SMD. State commissioner representatives serving as "advisory" members of oversight panels would do little or nothing to improve the governance of ITPs or to prevent gaming of the markets. NMPRC remains unconvinced that FERC can effectively monitor wholesale markets.

The Public Utility Commission of Nevada (PUCN) is very concerned with the jurisdictional over-reaching of the SMD NOPR. It intrudes on PUCN's statutory responsibility to protect Nevada's retail ratepayers. In its proposed rule, FERC has exceeded its statutory authority. FERC proposes to supplant time tested state policies that protect service and rates to retail consumers with new and untried institutions and rules implementing a market theory that has not been proven to benefit consumers. PUCN urges FERC to withdraw the NOPR.

1. The proposed rule is an unjustified expansion of FERC jurisdiction.
    1.1. The proposed regulations over matters and utility practices that fall within the jurisdiction of the states constitute an ultra vires act. FERC's unprecedented assertion of jurisdiction over bundled retail service, retail demand response, and generation resource planning and adequacy infringes on state jurisdiction. See §201(a) and (b) of the FPA (pp. 4-7).
    1.2. The alleged discrimination of vertically integrated utilities that prefer their own customers is not and cannot be shown to be undue. Section 206 provides that FERC must find undue discrimination. Utilities in Nevada that favor native load are fulfilling their obligations under state law. This cannot amount to undue discrimination. Congress indicated a clear policy preference for preservation of utilities' ability to fulfil their primary role to serve native load. See §§ 206, 211(d), 212(a), 202(b), and 212(g) of the FPA (pp. 7-9).
    1.3. The evidence alleged in the NOPR to support a finding of undue discrimination consists principally of undocumented claims and theoretically problems that, if they exist at all, can be addressed without the need of the sweeping reforms proposed.
        1.3.1. Meeting load growth is a requirement of utilities under Nevada state law. Using new or existing facilities to serve native load is not unduly discriminatory. Moreover, the remedy for disputes concerning reservations for future growth in native load is to enforce Order 888 (pp. 10-11).
        1.3.2. There are scheduling advantages in a large portfolio of generators and loads. Thus, many states have chosen not to unbundle utility service and implement retail competition. A utility's use of its own generation and transmission to maximize value and benefit its retail customers is not undue discrimination (pp. 11-12).
        1.3.3. The ATC calculation issue is controversial. The sweeping panoply of full operational divestiture and prohibition of vertical integration in order to solve any problem of inaccurate ATC calculation is unnecessary. Preservation of the native load exemption is appropriate. Establishment of either a general or contingent requirement for auditing of ATC by an independent party (or state commission) would be an effective remedy (p. 12).
        1.3.4. The NOPR provides no evidence or argument that the proposed remedies of operational divestiture, new institutions, new markets, and new regulations are necessary to address any problems that might occur in the reservation of capacity benefit margin (p. 13).

2. The proposed rule implements a misdirected competition policy that will disrupt existing state and regional service policies and increase risks to reliability of service and price stability.
   2.1. The singular emphasis on a market-based system would disrupt the availability of states like Nevada to preserve a cost based, public service model. Nevada and more than thirty other states have chosen not to implement a policy of retail competition for most electricity consumers. FERC's proposed market-based system would interfere with utilities' ability to serve their customers and fulfil their service obligations on a cost of service basis under state law (pp. 14-17).
   2.2. The proposed rule exposes consumers to new and extraordinary risks affecting a service vital to the economy. The NOPR provides no quantitative and credible evidence of the net benefits consumers would receive from implementation of SMD. No estimate of the cost for establishing new ITPs or for operating the complex web of centralized markets envisioned by FERC is provided. The lessons learned from California's establishment of these kinds of markets suggest that the expenses to comply with the proposed rule will be great (pp. 17-18).
3. The SMD is largely conceptual, incomplete, and internally inconsistent, and therefore it does not allow adequate opportunity for detailed comment and due process for affected parties and state governments before adoption. By PUCN's count, the NOPR leaves more than 100 important issues expressly unresolved. It is arbitrary, capricious, and procedurally insufficient for FERC to dictate that solutions must be found to problems that are alleged to exist, but that remain undocumented.

The New York Public Service Commission (NYPSC) supports FERC's objective to create seamless wholesale power markets. While it anticipates implementation of SMD will eliminate several existing seams problems, FERC should accommodate regional variation, provided they do not significantly impede interregional trade.

1. The New Transmission Service. The ITP should consider the effects on public health and safety when load shedding is required. Tying CRRs with physical rights and then using physical rights as the basis for load shedding might jeopardize public health and safety. FERC might instead allow the ITP to consider the effects on public health when curtailing load (pp. 5-7).
2. Transmission Pricing.
   2.1. Pancaked rates should be eliminated immediately. The SMD should provide that all exporting RTOs, including those that are only passed-through, should be allowed to recover their embedded costs. Moreover, clarification is needed to explain how the load share ratio would be calculated (pp. 8-10).
   2.2. License plate rates should not be eliminated. License plate rates are more efficient than postage stamp rates because they accurately reflect delivery costs and properly place such costs on those that receive benefits (pp. 10-11).
3. Day-Ahead and Real-Time Market Services.
   3.1. The SMD approach resembles the New York market design. NYPSC urges FERC to approve the proposal in the SMD.
   3.2. Transmission losses should be recovered on the basis of the marginal cost of losses (pp. 11-12).
   3.3. Lumpy generators should be allowed to set prices in the day-ahead market (pp. 12-14).
4. Other Changes To Improve the Efficiency of the Markets under the SMD. FERC should not adopt a bright line voltage test for determining what transmission facilities must be under the control of an ITP (pp. 14-15).
5. Market Power Mitigation and Monitoring in Markets Operated by the ITP.
   5.1. A $1000 per MWh safety-net bid cap is appropriate (pp. 16-17).
   5.2. FERC should establish a formula and process for setting bid caps/reference levels (pp. 17-19).
   5.3. Reference levels should not include an adjustment for opportunity costs (pp. 19-21).
   5.4. Under most circumstances, scarcity premiums for peaking units would not be just and reasonable (pp. 21-23).
   5.5. Market monitoring functions should be divided between separate entities. Because there are distinct and separate market monitoring functions, FERC should consider requiring two separate market monitoring units. For example, day-to-day monitoring should be done from within the ITP. The market monitoring unit should report to the ITP Board of Directors. This unit's function would be to implement the policies and rules proposed by the Outside Market Monitor (OMM) and FERC. However, analyses of the functioning of the market, the conduct of individual market participants, and market mitigation recommendations should be conducted by an OMM (pp. 23-25).
6. Governance for ITPs.

6.1. The proposed stakeholder committee structure reasonably reflects all industry segments (pp. 26-28).
6.2. Boards should be designed to ensure stability while encouraging continuous infusion of new ideas (pp. 28-31).

The Public Utilities Commission of Ohio (PUCO) divides its comments into four areas.

1. Structural Recommendations.
   1.1. Ohio's first priority is the Midwest Single Market Design. Ohio recommends that FERC move forward with the Midwest joint and common market initiative. This could serve as a test case for phasing in SMD. This would allow the flexibility, timing, and opportunity for adjustments that may be required prior to moving toward implementation on a national scale (pp. 7-8).
   1.2. Ohio supports ITCs, believing that for-profit transmission companies can be more innovative as well as provide an extra layer of independence from market participants and generation (pp. 8-9).
   1.3. The concept of an ITP needs to be very well defined and its role made explicit. Is an ITP simply a "tariff administrator"? Is it not-for-profit? Does it operate certain markets like energy or capacity markets? (pp. 9-10).
2. Economic Recommendations.
   2.1. It is important to recognize regional differences and the importance of timing in implementing an interim tariff (p. 10).
   2.2. Rather than prescribing "tight power pool" rules for congestion management across the Midwest market, Ohio strongly encourages FERC to allow the new regional ITPs responsible for running the LMP system to develop the detailed rules necessary to incorporate specific regional needs (p. 12).
   2.3. Ohio recommends that the adoption of a methodology that reflects cost causation principles to reduce undo cost shifts. The ratemaking process should require involvement by the affected states to capture the historical expertise and institutional knowledge that exists (p. 12).
3. Reliability Recommendations. Reliability standards must be honored by all market participants and upheld even above commercial interests. ITPs or their designees, approved by FERC, must be granted security coordination authority by NERC to enforce NERC and regional council standards (pp. 12-14).
4. Market Monitoring Enforcement.
   4.1. Ohio asks FERC to require equitable sharing of market monitoring information with state regulatory commissions, under seal or consistent with state rules for confidentiality as necessary, to individual states directly and immediately affect by market abuse. FERC should also resolve interrelated concerns and inconsistent policy subject to its Critical Infrastructure NOPR (pp. 14-15).
   4.2. AMP must work efficiently if applied across large or extensive ITP areas while adjusting for hub-specific differences, seasonality, weather patterns, non-coincident peaks, and different time zones (pp. 16-17).
   4.3. Ohio believes that triggers should not be rigidly set but should accommodate unexpected changes in market behavior. Recent history has proved that innovative profit-seekers will be able to find "loopholes: in poor market design and take advantage of them. Market monitors should have the flexibility to develop new approaches to deal with novel circumstances (p. 17).

The Pennsylvania Pubic Utilities Commission (PAPUC) agrees with FERC that a national wholesale market is urgently needed. PAPUC asserts that those who say SMD is based on a theoretical, unproven design are in error. PJM has demonstrated that SMD can be effectively implemented. PAPUC goes on to comment on some specific issues.

1. FERC's assertion of jurisdiction over all transmission services is appropriate. In *New York v. FERC*, 122 S. Ct. 1012 (2002), the Supreme Court held that FERC has the authority to apply its open access requirement to the transmission component of the wholesale electric market and the transmission component of the unbundled retail transaction in interstate commerce. There is no language in the FPA that limits FERC's transmission jurisdiction to the wholesale market only. *See New York v. FERC*, 122 S. Ct. at 1023-24. Additionally, FERC has attempted for years to remedy unduly discriminatory practices in interstate transmission services. Vertically integrated transmission owners continue to use interstate transmission assets to inhibit competition in wholesale power markets. Accordingly, FERC has the authority to exercise jurisdiction over the transmission portion of a bundled retail transaction in order to prevent undue discrimination. However, FERC should keep in mind its assertion that it will work with the states concerning rates for unbundled retail service (pp. 13-17).
2. PAPUC is especially sensitive to the issue of native load preferences for wholesale power transactions going to bundled retail load. Such a preference is at odds with a properly structured competitive wholesale market, and cannot provide the reliability and security that is sought. Similarly, the preferred treatment of native generation by the investor owned utilities must be avoided. Such behavior discourages new investment in generational resources and the marketing efforts of suppliers (p. 18).
3. Regarding the role of ITCs, PAPUC concludes that they have an irreconcilable stake in the market and cannot be structured to be completely neutral. Transmission competes directly with generation and load response for congestion relief. Thus, ITCs cannot serve as ITPs. They will not have the requisite independence to avoid undue discrimination (pp. 19-22).
4. In existing RTOs and in the SMD NOPR transmission owners are indifferent to congestion. It is essential to bring transmission owners into SMD as stakeholders to the extent that their economic investment and operations decisions are aligned with the economic optimization of the bulk power markets (pp. 22-25).
5. PAPUC suggests that the rule be redrafted to permit legitimate use of CBM by approved RTOs and ITPs (pp. 25-26).
6. There will always be load pockets on the grid. Some of these will also suffer from local market power. PAPUC proposes a "proxy competitive price", derived either from historic unconstrained hours in the region on different days, or proxy LMP prices for the hour in unconstrained regions outside the load pocket. Local market power will continue to be an issue until the load can directly bid into the wholesale market in real time. It is essential that FERC include some improved local market power mechanism as part of the SMD (pp. 26-29).
7. PAPUC suggests adopting postage stamp pricing as the sole transmission rate design principle in the SMD rule. The principal problem that is avoided using zonal rates is a

thorny problem of allocation of revenues. The second problem is eliminating zonal rates may introduce incorrect economic signals (pp. 30-31).

8. Stakeholder representatives with useful operating expertise must address, but not control, the many operational and technical issues to be resolved by the ITP in the implementation of a SMD. ITP boards must be free to implement the recommendations of their MMUs without the possibility of interference from their stakeholders. The proposed qualifications for board members and the requirement that they divest themselves of potentially conflicting financial interests are reasonable. However, PAPUC strongly oppose the selection of board members by a nominating committee. Limiting the selection process to a small committee of stakeholders decreases the legitimacy of the process and increases the chance that personal prejudice or the exercise of undue influence could affect the outcome of elections. Accordingly, it is suggested that the existing board be responsible for selecting nominees to the board (pp. 31-33).
9. PAPUC urges that CRR holders not be given a physically superior right to transmission capacity during times of shortage (See SMD Order at ¶159). CRRs are a financial right, not a preferential physical right in times of congestion (pp. 33-34).
10. In general, ex post pricing is preferable because it permits generators to self-schedule in response to market signals and requires less operator intervention (pp. 34-35).
11. PAPUC supports the inclusion of marginal transmission losses in LMP pricing (p. 35).
12. PAPUC urges deleting the provision contained in ¶ 307 of the SMD Order from the final rule. This provision, proposing that successful bidders locked into hourly prices in the day-ahead market rebid those accepted bids in the real-time market, seems to strike at the heart of the day-ahead market and is an invitation to market power and gaming (p. 36).
13. PAPUC recommends deleting the proposal in SMD ¶¶ 320-325 that would require the creation of a real-time ancillary services market for spinning and supplemental reserves (p. 36-38).
14. Regarding the proposal for system security in § M of the SMD Order, PAPUC reminds FERC that the NERC CIPAG is not an open forum for the development of standards and hence should not be viewed in the same category as NAESB. FERC should also recognize that the current NERC security guidelines are inconsistent with the Office of Homeland Security direction for threat levels. The SMD final rule should require that industry developed standards conform to national homeland security standards, in accordance with Executive Order 13231, Critical Infrastructure Protection in the Information Age (16 October 2001) (pp. 38-43).
15. Demand response initiative should be broad enough to reach as many participants as possible. PAPUC supports programs at the wholesale and retail level (pp. 43-45).
16. PAPUC agrees that the MMU must have access to all market and operations data. The MMU is expected to share its analyses and reports with the management of the ITP and the RSAC. However, PAPUC strongly believes this information should also be shared with individual state commissions, subject to appropriate propriety and confidentiality agreements (pp. 45-46).

PG&E Corp. (PG&E) supports FERC's efforts to remedy undue discrimination in the provision of interstate transmission services and develop electric wholesale energy markets in all regions. The fundamental components of the proposed restructuring are necessary and appropriate. There are several limited areas, however, where PG&E proposes changes to assist FERC in achieving its objectives effectively and expeditiously.

1. With respect to the interplay between federal and state regulators, transmission owners and other market participants are often caught in the middle. Issues surrounding resource adequacy and transmission planning are particularly difficult. Market participants must have clear guidance concerning whether federal or state authorities have jurisdiction over each substantive issue related to market design, and then have assurances that the regulations promulgated by that regulatory authority will not be subjected to second-guessing by another regulatory authority.
2. Transmission owners must be able to fully recover the costs arising from obligations to maintain the level and quality of service to existing grandfathered transmission contracts. FERC should clarify this issue so that utilities that move to ITP structures are not penalized.
3. PG&E urges FERC to encourage functional separation between ITCs & ITPs.

PJM Interconnection, L.L.C. (PJM) strongly endorses SMD. In a few limited areas, however, FERC should allow a degree of regional flexibility and phased implementation of certain SMD features.

1. Market Design
   1.1. The basis framework of SMD is sound. PJM's successful implementation of the vast majority of SMD features demonstrates the benefits to the public that can result from implementation of SMD.
   1.2. PJM fully supports the following features of SMD:
      1.2.1. LMP based congestion management;
      1.2.2. Payments based on efficient market clearing prices;
      1.2.3. NAS throughout the ITP;
      1.2.4. Day-ahead and real-time markets;
      1.2.5. CRRs and ARRs;
      1.2.6. Incentive-based, voluntary unit commitment and dispatch premised on markets sending proper price signals and market participants acting voluntarily in response to those price signals;
      1.2.7. Market systems that support both bilateral and spot market transactions.
   1.3. There are a few areas where the NOPR proposes market design features that may actually lead to results at odds with FERC's goals:
      1.3.1. Hourly bidding;
      1.3.2. Some SMD features are technically impractical in the near term for very large markets;
      1.3.3. Day-ahead reserve markets.
2. Role of NAESB. FERC stresses the importance of independence and the need for ITPs to be independent of stakeholders; yet, the NOPR simultaneously contemplates that the NAESB, an entity run by stakeholders, will develop the market standards to be utilized by ITPs. To reconcile these proposals, FERC should make clear that ITPs will provide advice to NAESB on proposed standards, and NAESB should be required to take into account that advice.
3. Role of ITCs. FERC has established a framework for the split of functions between ITPs and ITCs in its decisions. ITCs should not be ITPs. ITCs are competitors in the marketplace for solutions to congestion. One transmission owner—an ITC—should not decide whether other ITCs, merchant transmission owners, or others may proceed with their projects.
4. Governance of ITPs. Independent governance of ITPs is crucial to the successful implementation of SMD. The principles for ITPs therefore should ensure that no stakeholders have undue influence over the election of board members or management of ITPs.
5. Market Monitoring. PJM generally concurs with the NOPR's market monitoring proposals. However, the MM should not have authority to impose penalties.
6. Other Matters.
   6.1. Need for coordination and scheduling of transactions at ITP borders;
   6.2. Need for liability and indemnity for the ITP;
   6.3. Need for software standardization and system security;
   6.4. Need for credit requirements for participants in ITP markets.

The PJM Transmission Owners Group (PJM Transmission Owners) generally supports FERC's direction in the SMD NOPR. However, The PJM Transmission Owners have several specific concerns.

1. The language of the NOPR can be read to suggest that FERC intends to allow unilateral "conversion" of pre-existing contracts. The PJM Transmission Owners seek clarification that FERC is not proposing to abrogate pre-Order No. 888 contracts. If the effect of the NOPR is to allow the transmission customer to abrogate contracts, a violation of the *Mobile-Sierra* doctrine will result. The PJM Transmission Owners submit that pre-Order No. 888 contracts should be treated the same under SMD rules as they were under Order No. 888; they should be grand fathered without altering their terms or the contractual parties, unless contract conversion is specifically permitted by the terms of the pre-existing contract. Moreover, in PJM and in New York, transitions to RTO regimes were successfully accomplished without abrogating contract rights.
2. The governance proposal set forth in the NOPR is more specific than necessary and does not adequately accommodate regional variation. The PJM Transmission Owners and its stakeholders have put into place, with FERC approval, a set of procedures that, while containing details that are not exactly as those described in the NOPR, are fully in keeping with the independence features that the NOPR is advancing. Accordingly, FERC should allow those governance procedures to remain in effect upon implementation of the final rule.
3. Appropriate liability provisions are required for transmission owners to manage risks flowing from the ITP operational control of their assets.
   - 3.1. FERC-jurisdictional transmission service is at issue. The state commissions lack jurisdiction over this interstate service. Even in states where retail rates remain bundled, in the instant NOPR FERC asserts jurisdiction over the transmission component of bundled retail rates. Thus, it is not appropriate, as a matter of law, to rely upon the states to provide liability protection. Moreover, state laws vary, and it is unclear in the multi-state RTO/ITP context which state law would apply.
   - 3.2. Absent adequate liability protection in the pro forma tariff, transmission owners/providers will be exposed to potentially catastrophic damages awards.
   - 3.3. The need for a limited liability provision applicable to transmission owners is particularly strong where the transmission assets will be operated by a different entity, the ITP, such that there is a split between ownership and operational responsibility.
   - 3.4. The PJM Transmission Owners submit that the standard for a limitation of liability provision should be as follows: transmission owners should be subject to direct damages only, and not to consequential, incidental, special, or punitive damages.

The South Carolina Public Service Commission (SCPSC) opposes adoption of the SMD NOPR. SCPSC argues that FERC lacks the authority to issue the NOPR as a final rule, and that there is no evidence of undue discrimination. South Carolina has not restructured its retail electric power industry, has not opened its retail electric markets to competition, and has not required or encouraged vertically integrated utilities to restructure.

1. SCPSC submits that FERC lacks jurisdiction to mandate the SMD.
   1.1. Under §202(a) of the FPA, FERC has no authority to mandate RTO formation. The effect of the proposed rule would be to compel participation in a RTO. A mandatory RTO policy cannot stand in view of FPA §§202(a), 202(b), 210, 211, and 212. Read together in the overall framework of the FPA, these sections provide FERC with two options. (1) FERC may promote the formation of voluntary regional organizations under §202(a). (2) FERC can exercise jurisdiction through its adjudicatory powers conferred by §§202(b), 210, and 212. However, adjudicatory jurisdiction requires fact-findings on a case by case basis. As further discussed below, no such fact-finding has been conducted. FERC lacks the authority to create a third option for promoting regional organizations, i.e. implying that it may use a generic rulemaking process to remedy undue discrimination in the abstract. Although FERC has the authority to compel transmission and interconnection under the FPA §§210, 211, 212, these sections are adjudicatory in nature and do not contain authority to act on the basis of generic findings. (pp. 7-11).
   1.2. SMD violates §§201(a) & 201(b) of the FPA. According to these sections FERC's jurisdiction over the transmission and sale of electric energy for ultimate distribution to the public shall "extend only to those matters which are not subject to regulation by the states," and shall not have jurisdiction over facilities used for generation. The SMD NOPR crosses these bright lines of demarcation between its jurisdiction and that of the states (pp. 11-16).
2. Even assuming arguendo that FERC had the authority to impose SMD, the proposal still fails for lack of substantial supporting evidence. In this regard, FERC fails to distinguish between states that have opened their retail markets and those that have not (pp. 16-18).
   2.1. The NOPR is predicated on a factual premise that in each state competition is replacing regulation and that competition is being infected with undue discrimination. This premise is seriously flawed. There is no inexorable transition toward competition, particularly in the retail market. Since the fundamental factual premises are unsupported by any substantial evidence, and indeed are refuted by a preponderance of the evidence, FERC would make an arbitrary, capricious, and unreasoned decision were it to adopt SMD (pp. 16-17).
   2.2. Moreover, the assertion that all open access tariffs provide transmission owning public utilities with the means to favor their own generation and retail customers, which in turn leads to undue discrimination, is unfounded. Under South Carolina law, retail competition is not permitted. Thus, it is legally and factually impossible for a vertically integrated public utility with in-state transmission facilities to give preferential treatment to its own retail customers which results in discrimination against other retail customers who also rely on the public

utility's transmission facilities. Likewise, it is impossible for undue discrimination to exist between a public utility's service to its wholesale and retail customers. Under South Carolina law, retail customers are entitled to the preferences now accorded under open access tariffs. Electric utilities subject to the South Carolina Code have been required to construct and operate facilities solely to provide reliable service to their native load customers. South Carolina retail customers have paid for the native load preferences. It is not unduly discriminatory to give them preferential treatment (pp. 17-18).

The South Dakota Public Utilities Commission (SDPUC) requests that FERC fully, carefully, and favorably consider the comments made by the Washington Utilities and Transportation Commission and of the allied New Mexico Attorney General, the Rhode Island Attorney General, the Colorado Office of Consumers Counsel, the Utah Committee of Consumer Services, the Public Utility Law Project, and the National Consumers Law Center regarding the SMD NOPR. These comments do not support the legal or theoretical bases relied upon by FERC. SDPUC believes the SMD will increase the cost of transmission and generation. South Dakota, a rural and low-income state, cannot afford the "benefits" promised by SMD. SDPUC strongly urges FERC to carefully consider the enormous costs of establishing, administering, and ultimately living with, SMD.

The Tennessee Regulatory Authority (TRA) commends FERC for its efforts to address undue discrimination in the electricity industry. TRA has many concerns, however, about the process outlined in the NOPR to remedy the problem.

1. The NOPR provides no specific evidence that preferential use of transmission to serve native retail customers has been abused by utilities anywhere in Tennessee or in the Southeast. The proposed rule offers only theoretical examples of how vertically integrated service to native load could disadvantage other utilities. Further, the NOPR provides no specific evidence that ultimate consumers have been, or would be, harmed if utilities continue integrated operation of transmission and generation primarily to serve their customers. TRA would like FERC to make a specific finding of undue discrimination for at least one region, and to show that the undue discrimination in the pricing or access to transmission has a significant effect on the average price and competitiveness of power in the wholesale generation market. Moreover, FERC should show that the economic efficiency of the entire transmission and generation system would be significantly enhanced by the proposed SMD (pp. 7-10).
2. In regions of the country where the separation of transmission from generation has been addressed through the creation of ISOs, market design flaws create inefficiencies in the marketplace and opportunities for the exercise of market power. Clearly, FERC-approved market design experiments have led to problems in some cases. Before a new nationwide SMD experiment is implemented, FERC should provide a detailed analysis of what went wrong with existing experiments (pp. 11-12).
3. FERC does not appear to have considered alternative solutions. Such alternatives could include enforcement of existing rules by FERC, state commissions, or RTOs and ITPs. Alternatively, FERC could fix loopholes identified in Order 888. FERC could also create a mechanism to detect and deter the exercise of market power (pp. 12-14).
4. TRA agrees that the lack of common rules governing the operation of a transmission system makes it difficult for that system to support an efficient regional electric power market. TRA disagrees, however, that a single common set of rules must govern the operation of all transmission systems in the U.S. Many regional differences exist, and these should shape any SMD (pp. 15-16).
5. Tennessee is among the states that have chosen not to implement retail competition for retail consumers. Most utilities operate under state laws that impose on them an obligation to meet the service needs of their customers. This system has worked well for decades; consumers enjoy reliable and inexpensive electricity service. FERC's proposed rule will fundamentally disrupt the ability of states to maintain a cost-based, public service electricity system, because the rule prohibits a utility from coordinating the operation of its generating and transmission facilities (pp. 16-18).
6. FERC proposes its own solutions as a basis for comment, leaving no room for states to present alternative solutions. Furthermore, the timetable for the SMD is very aggressive and does not allow enough time for input from stakeholders. TRA would prefer that there be no date set in the NOPR and that regions have the opportunity to comply with elements of the SMD in phases (p. 18).

7. TRA remains concerned that SMD will allow market participants to take advantage of differences among regions, raising energy prices for those in low-cost energy regions. TRA strongly opines that FERC needs to show how the SMD will prevent transmission owners and power generators from exploiting the system as they did in California. Congestion and inadequate infrastructure are the result of wholesale deregulation, and TRA has not been convinced by the evidence thus far presented by FERC that further deregulation holds the most promise for solving these problems. Additionally, TRA believes that consumer-owned utilities, federal electric utilities, and federal marketers should remain exempt from FERC's jurisdiction. TRA's preferred course of action would be that FERC suspend or withdraw the NOPR and convene a contested case hearing on the matter (pp. 19-21).
8. TRA opposes the expansion of FERC jurisdiction to include bundled retail transmission service, retail demand response, and generation resource planning and adequacy. FERC is urged to omit the sections of the NOPR that purport to give FERC such jurisdiction (pp. 21-24).
9. The NOPR calls for bidding out of transmission rights. This means that ratepayers who paid for a particular transmission system would not be guaranteed access to that system. TRA believes that the NOPR should be withdrawn to allow the U.S. Congress to put in place SMD legislation that will guide FERC in this effort. TRA also believes that using CRRs to allocate transmission costs would be inconsistent with the principles of cost causation and should be abandoned. This will be addressed in the 10 January 2003 comments (pp. 24-26).
10. The NOPR is silent on how participant funding will be implemented. TRA supports participant funding, yet feels much more detail on its implementation is needed for stakeholders to make informed comment (pp. 26-27).
11. Regarding LMP, FERC has not shown that once the SMD is implemented the resulting rates will likely be just and reasonable or that economic efficiency will most likely be enhanced relative to the risks created (pp. 27-28).
12. While TRA agrees that ex-post pricing of imbalances is appropriate, the mechanism provided in the NOPR should not be the only one considered. Alternative methodologies, such as Wide Open Load Following (WOLF) should be given consideration (pp. 28-29).
13. Although the NOPR invites each ITP's MMU to conduct a market assessment, it lacks directives on how market power is to be measured and identified. TRA believes that these measures are still too vague. Because experience has shown that FERC may fail to recognize and prevent the abuse of market power, TRA strongly prefers a clear definition of market power (pp. 29-31).
14. A regionally coordinated effort can protect customers and minimize congestion, provided that FERC involves state commissioners and takes into account their input. TRA has many questions about the proposed RSACs. The most appropriate entity would be a joint board created pursuant to §209 of the FPA.
15. Finally, TRA is concerned that the NOPR's requirements for a regional planning process are not clear (p. 34).

TRANSLink supports the broad objectives of the NOPR. In order to harness the capabilities of independent, commercial transmission companies to support the wholesale markets proposed in the NOPR, FERC must permit ITCs to expand their roles and responsibilities. TRANSLink's comments offer recommendations on how the proposed SMD rule may be enhanced to foster the development of a viable and vigorous independent transmission sector. FERC is urged to remain open to granting greater responsibilities to ITCs. TRANSLink believes that ITCs can perform many functions under an ITP and can function as an ITP. Further, ITC roles and responsibilities within an RTO can be allocated on the basis of considerations of regional coordination.

TRANSLink believes that FERC should establish principles by which it will evaluate ITP governance proposals but not dictate a particular solution. FERC's governance standards should permit for-profit models for RTOS, ITPs and ITCs functioning as ITPs.

FERC must adopt a sensible, balanced, robust transmission planning and expansion process. The principle of competition should not be extended from the generation to the transmission sector. To get the requisite transmission expansion to meet the vast majority of future reliability and market needs, FERC will need to rely on a mix of at-risk participant funded and merchant transmission expansion and regulated, rolled-in expansion.

FERC should establish a single federal standard of liability limitation. This standard should reflect the predominant policy choices previously adopted by the states—protection from liability in cases of simple negligence, but not gross negligence or willful misconduct.

TRANSLink believes that SMD needs the full participation of non-jurisdictional entities to succeed, particularly in the West.

The Public Utility Commission of Texas (PUCT) wholeheartedly supports the goals and most of the elements of the SMD NOPR. Texas is in the process of implementing retail competition, and a vibrant wholesale market is essential for retail competition. PUCT does articulate several concerns however.

1. Existing RTO Formation Process
   1.1. PUCT is concerned that in proposing the SMD rule, FERC may be backtracking on requirements adopted in Order 2000. An important element of wholesale markets is the formation of RTOs. PUCT is concerned that allowing utilities to form ITPs could delay the introduction of independent transmission management, market-based congestion management, and markets for ancillary services; could prolong seams problems, including pancaking; and could frustrate efforts to regionalize transmission planning (p. 5).
   1.2. Broadly stated, an issue with respect to the existing RTO formation process and how it related to the SMD is that of geographic scope. The SMD rule should be a means of effectuating the goals of Order 2000, to get utilities to join RTOs in order to enhance the efficiency of regional transmission markets. PUTC is concerned that, instead, it will provide utilities a means of operating outside of an RTO by creating small ITPs, a result that will complicate the provision of transmission service, the management of congestion, and fragment the energy markets within the broader region (p. 6).
   1.3. The existing investment by some RTOs in operating systems raises an important transition issue. It is appropriate to provide a longer time for implementing all the elements of SMD. RTOs that are in early stages of development, such as SeTrans, should comply with the SMD rule and the timetable for implementing it (p. 7).
2. PUCT is skeptical that the independent transmission providers envisioned by the SMD could achieve the level of independence necessary to engender the confidence of transmission customers (pp. 7-8).
3. The open-access tariffs in effect today are not conducive to competition at the retail level. The reforms proposed in the new network access service would provide new retail providers and new generating facilities access to the transmission system on the same terms as the incumbents. There may be several ways to reform transmission rates. PUCT is concerned that the rate design FERC has proposed would result in rates that would not support the construction of new transmission intended to facilitate inter-system transactions (pp. 8-10).
4. Congestion Management
   4.1. PUCT generally supports the principles behind the SMD rule's use of LMP for congestion management. In its view, there are several possible ways to manage congestion through locational prices, and each region should have the flexibility to adopt an appropriate system. ERCOT currently uses a simplified zonal model. Beginning in 2003, ERCOT will use a simultaneous, combinational auction of flowgate rights that will allow market participants to purchase flowgate rights in bundles (p. 10).
   4.2. The zonal approach has been effective in ERCOT because the topology of the grid is significantly different from the topology of the Eastern Interconnect.

PUCT assumes that there are differences in topology among the systems around the country. Therefore, it recommends FERC allow for the possibility that congestion management systems incorporating variation of the nodal approach may be appropriate for some regions (pp. 11-12).

5. Day-Ahead and Real Time Markets
   5.1. PUCT supports the SMD rule's requirement that RTOs and ITPs conduct markets for balancing energy and ancillary services. Currently, ERCOT operates a real-time balancing market (p. 13).
   5.2. An ITP may be in the best position to operate a day-ahead market for the early stages of market operation. However, the operation could be privatized over time (p. 14).
   5.3. The ERCOT wholesale market uses ex-ante pricing. PUCT believes FERC should allow each RTO or ITP to select ex-post or ex-ante pricing (p. 14).
6. PUCT believes it is essential to have market power mitigation tools in place (p. 15). It supports methods such as the New York ISO's automatic mitigation procedure to mitigate the abuse of market power (p. 16).
7. In ERCOT, an offer cap of $1000 per MWh has been in place since 31 July 2001. PUCT does not see any strong reason for a uniform safety-net bid cap across all markets. Rather, the bid cap should be determined regionally. The cap should be set in such a way that it is not an impediment to the installation of new resources that would increase the supply and reduce market concentration in a region (p. 15).
8. Market Monitoring
   8.1. The key issue is true independence of MMUs (p. 17).
   8.2. In contrast with the majority of MMUs, which are located within their corresponding RTOs, the ERCOT market monitoring function is located within the PUCT. PUCT established the Market Oversight Division (MOD). While being outside of the ERCOT system and having full access to date provides significant independence to MOD, it has also resulted in two crucial shortcomings.
      8.2.1. As part of a state agency, financial resources are limited and cannot keep pace with the need for staff expertise and computer models (*Id.*).
      8.2.2. MOD is physically removed form daily market operations and therefore does not have ready access to operational personnel (*Id.*).
   8.3. Given that an ITP is an essential part of market operation and could engage in undue discrimination, it is appropriate for MMUs to monitor ITPs' market operations (*Id.*).
9. The objective of standardizing market design should be to standardize where doing so will support the creation of large regional markets. PUCT is particularly concerned about the standardization of the Eastern Interconnect, because the potential exists for two separate RTOs (SeTrans and MISO) to operate within East Texas. If the market rules for these two RTOs diverge significantly within this relatively small area, the result would be two distinct wholesale markets, rather than a single market. PUCT does not believe that it is essential to standard rules across the country (p. 18).

The Utah Public Service Commission (UPSC) joined by the Utah Division of Public Utilities and the Utah Committee of Consumer Services note that serious damage may be done to public and consumer interests unless the SMD is scaled back and reformulated. UPSC urges FERC to follow through with its prior RTO initiative rather than impose the SMD upon state jurisdictions.

1. UPSC does not support FERC regulation of bundled electricity retail rates as a means of addressing its perception of "undue discrimination". Moreover, UPSC does not find systematic, coherent , and complete analysis supporting the SMD NOPR (pp. 1-2).
2. An appealing aspect of FERC's RTO initiative is its state-approval requirement. The ITP within the auspices of the SMD would appear to perform the RTO function, but without the state approval requirement (p. 2).
3. UPSC notes that FERC focuses on the SMD as a vehicle for fostering a more effective wholesale power supply market. FERC might better serve the country by resuming its more modest, historical agenda of fostering appropriate transmission infrastructure and enforcing non-discriminatory wheeling rates (p. 2).
4. UPSC is particularly concerned with the clarity and propriety of the signal by which transmission congestion is translated to transmission system augmentation. In addition to the lack of an obvious nexus between congestion-generated revenues and long-run transmission system expansion, the specter of parties' "manufacturing" congestion where it would not otherwise exist so as to reap illicit congestion revenues is troubling (pp. 2-3).
5. Absent congestion, it is not clear that the revenue contribution of the native loads of incumbent utility/transmission owners will be fairly recognized. Rather than receiving a token payment obligation, non-load serving entities could be expected to pay some form of megawatt-mile charge as an equitable share of the related embedded costs of the facilities from which they benefit. Additionally, loads within a transmission owner's footprint may not grow enough to require the surplus capacity for decades. Those native loads should not be faced with having to pay additionally for new or augmented facilities at the time of their need due to their rights to the older facilities having been previously and permanently auctioned to the highest bidder (p. 3).

The Washington Utilities and Transportation Commission (WUTC) urges FERC to withdraw the SMD NOPR. The proposed rules are a profound and unjustified expansion of FERC jurisdiction. The proposed rules would implement a misdirected competition policy. Moreover, the proposed rules are largely conceptual, substantively incomplete, and internally inconsistent.

1. The Proposed Rules Are a Profound and Unjustified Expansion of FERC Jurisdiction into Matters Most Appropriately Addressed by the States.
   1.1. The NOPR's assertion of jurisdiction exceeds FERC's statutory authority. FERC exceeds its legal authority by reaching into state regulated retail service and resource planning. It is ironic that FERC relies on *New York v. FERC* as a basis for jurisdiction. In that case, FERC argued it had reasonably found that it lacked jurisdiction over the transmission of bundled retail sales under §201 (Brief of FERC at 50, *New York v. FERC*, *Enron v. FERC*. Nos. 00-568 and 00-809. May 2001.). Contrary to FERC's interpretation of the case, the Court did not reach this jurisdictional question. In any event, the case addressed only transmission jurisdiction, not jurisdiction over resource planning and adequacy standards, and not jurisdiction over retail demand management. Furthermore, the proposed rules will upset the current scheme authorized by Congress and operating under the Northwest Power Act (pp. 10-18).
   1.2. The alleged discrimination, wherein a vertically integrated utility prefers its own customers, is not and cannot be shown to be undue. FERC's "finding" that it is "undue" discrimination for a utility to favor its own retail load in order to satisfy state law is remarkable. In finding this kind of preference to be undue discrimination, FERC is repudiating and attempting to preempt the retail policies of the large majority of states. Since 1992, the Congress has considered many bills to preempt the states and to establish a national policy of retail competition, but has declined to do so. Without any basis for doing so, FERC now reinterprets the mandate and obligation that Congress has given it—to ensure just and reasonable rates—as a mandate to ensure competition (pp. 18-26).
   1.3. The evidence alleged in the NOPR to support a finding of undue discrimination consists principally of undocumented claims and theoretical "problems" that, if they exist at all, can be addressed without need of the sweeping reforms proposed by the rule (pp. 26-29). WUTC offers comments on the specific categories of problems the NOPR alleges.
      1.3.1. Load growth. Meeting load growth is a requirement of utilities operating under well-founded state law. Using new or existing facilities for a utility's primary purpose is not undue discrimination (pp. 29-30).
      1.3.2. Delays in responding to requests for service represent a true problem. However, improvements can be made by refining interconnection rules and enforcement of the pro forma tariff rules for processing requests. Additionally, with respect to alleged violation of the pro forma tariff, if FERC cannot effectively or timely enforce current rules, WUTC doubts it will be able to effectively monitor and police market power under the SMD (pp. 30-32).

1.3.3. Scheduling advantages. Under state regulation, the economic benefits of scale and scope that come from a large portfolio of generators and loads are encouraged and shared between the utility and its customers. A utility's use of its own generation and transmission to maximize value and to benefit its retail customers is not undue discrimination; it is the underlying principle, under state law, of a regulated utility to serve its customers efficiently (pp. 32-34).

1.3.4. Imbalance Resolution. FERC has provided no argument or evidence that its proposed remedy will result in imbalances being resolved. In fact, experience with volatility in real-time market prices suggests the opposite would likely occur: higher prices, more volatility, and less reliability (pp. 34-35).

1.3.5. ATC and affiliates. WUTC cites an example to highlight the need to examine the actual facts of a discrimination claim, and to construct a tailored solution to actual undue discrimination found, rather than proceed with the simplistic idea that a general remedy is needed because discrimination could occur. *Opinion No. 460. Arizona Public Service Company v. Idaho Power Company. 100 FERC ¶61,253 (5 September 2002)* (finding that Idaho Power acted appropriately when it excluded from ATC certain transmission capacity necessary to dispatch hydropower and serve native load) (pp. 35-37).

1.3.6. OASIS postings. This remedy can be accomplished with steps far short of the sweeping operational divestitures and new institutional markets and regulations proposed in this rulemaking. For example, FERC could require all utilities in a region to post ATC on a single, consolidated OASIS (pp. 37-38).

1.3.7. CBM manipulation. The NOPR provides no evidence that the proposed remedies are necessary to address any problems that might occur in the reservation of capacity benefit margin (p. 39).

2. The Proposed Rules Sever the Lines of Meaningful Political Accountability for a Service that is Inherently Political Because It is Vital.

2.1. The provision of electricity is inherently political because electricity is a vital public service. Therefore, electricity must be subject to government oversight that can effectively protect the public interest. Under the current system, there are strong links of accountability between the ratepayer, the state regulator, and the regulated utility. The proposed rule would seriously degrade the public accountability of critical electricity institutions (pp. 41-42).

2.2. Responsibility for transmission service, generation planning and adequacy, even aspects of retail demand, are proposed to be shifted form state and municipally regulated utilities to ITPs governed by corporate style boards and regulated solely by FERC. This transfer of jurisdiction wrests accountability from local and state officials and vests it no boards that are inaccessible and not accountable in any direct way to the ratepayers who will be vitally affected by the ITP's decisions (pp. 42-43).

2.3. Furthermore, in the Pacific Northwest, 80% of the transmission grid is owned by the public in the form of BPA and certain municipal and county-owned utilities.

WUTC understands the purpose of the reciprocity provisions of the NOPR. Yet, if the effect of these reciprocity provisions were to force the operation and management of BPA or municipal utility transmission into an ITP, there would be a transfer of management of a public asset from a public agency to a private corporate board (pp. 43-44).

2.4. Ultimately, accountability will shift to FERC. FERC is not practically accessible to ordinary citizens, or able to respond quickly and effectively to a pressing need for action in a state or regional market (pp. 44-45).

2.5. The NOPR claims that the proposed rules provide an important role for the states as key members of an advisory committee from which the ITPs are to seek opinions. The general issue of RSACs is among the issues to be addressed in later comments (pp. 45-46).

3. The Proposed Rules Expose Consumers to New and Extraordinary Risks Affecting a Service Vital to the Economy and Modern Life.

3.1. The NOPR provides no estimate of the cost for establishing ITPs, or the cost for operating this complex web of new, centralized markets for energy and other services. Absent any real cost data showing otherwise, the lesson we learned from California and other places that have established these kinds of markets is that the expenses to comply with the proposed rule will be great (pp. 47-48).

3.2. The risks of implementing a single market design across all regions of the country without regard to regional differences are great. Centralized energy markets have proved to be volatile, and susceptible to flaws, manipulation, and runaway prices where they have been implemented (Australia, New Zealand, and the U.K. are cited). Against such real risks and costs, FERC provides only theoretical estimates of benefits (pp. 48-52).

4. The Proposed Rules Increase the Cost and Difficulty of Utilities and Non-Utilities To Obtain the Necessary Financing To Build Necessary New Generation and Transmission Infrastructure.

4.1. In the current environment, vertically integrated, state regulated retail utilities may be vital in attracting the investment capital needed for new infrastructure. But, new rules and uncertainty regarding vertically integrated utilities and their obligations to meet load requirements and opportunity to recover costs may well undermine even their ability to raise capital. The available evidence indicates that the complexity and controversy introduced by SMD are working powerfully against FERC's objective to stabilize the investment climate for new generation and transmission (p. 52-57).

5. The Proposed Rule is Largely Conceptual, Substantively Incomplete, and Internally Inconsistent, and Therefore Does Not Allow Adequate Opportunity for Detailed Comment and Due Process for Affected Parties and State Governments Before Adoption.

5.1. Despite its length, the NOPR leaves expressly unresolved more than 100 important issues (pp. 57-61).

5.2. The NOPR's proposed rules are too important and too radical to proceed without a full opportunity for the public to digest, understand, and comment on a fully developed and fully defined SMD (pp. 61-62).

The Public Service Commission of Wisconsin's (PSCW) principal concern among the relevant topics in this round of comments is that consumers in Wisconsin may never realize the proposed benefits of such regulatory reform unless FERC first addresses structural market power issues. Because demand response programs and other interim measures will not necessarily be able to balance Wisconsin's lack of transmission infrastructure, the PSCW urges FERC to quickly and thoroughly address structural market power problems.

1. Market Power Mitigation and Monitoring in Markets Operated by the ITP
   1.1. In Wisconsin, structural market power issues are of special concern. Transmission constraints place Wisconsin on a load pocket where consumers generally are not able to reach alternative power suppliers (pp. 5-6).
   1.2. In light of the structural problems facing wholesale markets in several regions, FERC should immediately strive to facilitate transmission construction sufficient to ensure the LSEs have non-discriminatory access to robustly competitive wholesale markets. As first steps, FERC should:
      1.2.1. Preserve LSEs firm transmission rights so that the transition to CRRs does not harm LSEs (p. 6).
      1.2.2. Permit, where appropriate, the participation of new entrants and other LSEs in future generation projects (p. 6).
   1.3. Although the PSCW generally supports the market monitoring plan of the NOPR, it suggests that:
      1.3.1. Market date should be released more quickly (pp. 7-8).
      1.3.2. Market power monitoring and mitigation plans should be extended to all markets (pp. 8-9).
      1.3.3. Bid caps, triggers, and reference prices should be cost-based, including opportunity costs (p. 9).
      1.3.4. Monitoring should make use of the most relevant information (p. 9).
2. Governance for ITPs
   2.1. The PSCW supports the necessity of an independent governance structure for ITPs but is concerned that any required changes to MISO's governance could unnecessarily delay SMD implementation in the Midwest (p. 10).
   2.2. The PSCW is concerned that establishing a revised governance structure for MISO at this time could disturb the continuity of its existing board of directors and distract the resources of MISO from its wide-ranging existing commitments. For these reasons, FERC should consider grand fathering MISO's existing Governance, or provide MISO a phase in period for a new structure (p. 10).
   2.3. A related concern is that FERC has proposed that a single company would only be allowed a single representative on a stakeholder advisory board (p. 10).
3. Implementation
   3.1. The PSCW is concerned that a hastily crafted market power mitigation regime may result in unintended market power and reliability problems (p. 11).
   3.2. The logistical challenge for FERC, state commissions, market participants, and ITPs in implementing the SMD is enormous. The timeline for implementation may be too ambitious. FERC should consider implementing SMD gradually in order to identify and resolve unexpected problems (p. 12).

Williams Energy Marketing and Trading Company (Williams) unequivocally supports the concept of SMD and, subject to certain modifications, supports the specific proposals set out in the NOPR. Williams recommends that FERC:

1. adopt the SMD without delay, reiterating the impact on the elimination of anticompetitive and unduly discriminatory obstacles as well as the promotion of new and creative electric power transactions;
2. remedy the effect of subsidized generation on competition for electric power;
3. reconsider what Commissioner Massey described as "a significant policy shift" and apply the SMD findings and conclusions to prior RTO approvals acceptances; and
4. reconsider the usefulness of broad, national market intervention measures.

Xcel Energy Services Inc. (Xcel) supports FERC's efforts to promote competitive markets. However, it has serious misgivings with the SMD NOPR. Standardization of markets has appeal in the abstract, but Xcel feels that it is an impractical goal considering the significant regional differences in the electric industry. Moreover, the timetable for implementation is too aggressive. A more pragmatic approach would set out general guidelines, allowing market participants in a region, in conjunction with interested state commissions, to developed market design proposals.

Xcel also has concerns with the attempt by FERC to extend its jurisdiction in areas where it does not properly have jurisdiction. To the extent that SMD requires utilities to make forced wholesale sales, it is inconsistent with the FPA. Furthermore, the resource adequacy planning provisions exceed FERC's authority under the FPA. The result of such assertion of jurisdiction would be to impose conflicting requirements on operating companies. FERC may see its scheme as complementary to state resource planning requirements, yet Xcel is very concerned about being subject to competing requirements.

Despite its overall concern about FERC's approach in the SMD NOPR, Xcel does avail itself of the opportunity to comment on some aspects of the NOPR. Xcel is concerned that SMD would institutionalize discrimination by allowing for the grandfathering of transmission rights and by not requiring non-jurisdictional public power entities to adhere to the same requirements as jurisdictional utilities. Xcel agrees that the benefits of for-profit transmission companies should be considered for ITPs. Xcel supports a single NAS tariff and, eventually, the development of CRRs. However, FERC should avoid mixing physical rights with financial rights. Xcel also supports the two market system. Xcel does express concern, however, that market mitigation schemes will become a permanent part of the market infrastructure, thereby blunting appropriate price signals and diminishing the effects of competition. In particular, Xcel takes issue with the must offer requirement on both legal and policy grounds.