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STATE CORPORATION COMMISSION

January 31, 2003

VIA ELECTRONIC FILING

Honorable Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First St., N.E.
Washington, DC 20426

Re: Docket No. RM01-12-000, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design

Dear Secretary Salas:

Enclosed please find for electronic filing the Comments of the Virginia State Corporation Commission in the above captioned docket.

Thank you for your attention to this matter.

Sincerely,

Arlen K. Bolstad
Senior Counsel

AKB:nel
Attachment

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination	**)**	
through Open Access Transmission Service	**)**	**Docket No. RM01-12-000**
and Standard Electricity Market Design	**)**	

COMMENTS OF THE
VIRGINIA STATE CORPORATION COMMISSION
ON NOTICE OF PROPOSED RULEMAKING

I. INTRODUCTION

Pursuant to the "Notice of Proposed Rulemaking" ("NOPR") issued by the Federal Energy Regulatory Commission ("Commission" or "FERC") on July 31, 2002, the "Notice of Conferences and Revisions to Public Comment Schedule" issued on October 2, 2002 ("October 2 Notice"), and the "Notice on Requests for Additional Time," issued on December 20, 2002 ("December 20 Notice"), in the above-noted docket, the Virginia State Corporation Commission ("VSCC") hereby submits its initial comments on the Commission's proposed Standard Market Design ("SMD").[1] The Virginia

[1] The October 2 Notice bifurcated the procedure for submitting initial comments in this docket, with initial comments split into two rounds, to be filed on November 15, 2002, and January 10, 2003, depending on the issue addressed. On November 14, 2002, the VSCC filed a letter with the Commission in this docket indicating it would submit one comprehensive set of comments on all issues on or before January 10, 2003. In light of the advance grant of permission in the December 20 Notice for late filings by those commenters unable to meet the deadlines set out in the October 2 Notice, and the press of other business before the VSCC (including the preparation of three different filings with this Commission related to the proposals of certain Virginia electric utilities to join the PJM Interconnection, L.L.C.), the VSCC is filing its initial comments after January 10, 2003, but well before the filing deadline of February 28, 2003, set out in the December 20 Notice.

Commission has participated in earlier phases of this docket, submitting comments on November 14, 2001,[2] March 12, 2002,[3] April 9, 2002,[4] and May 1, 2002.[5]

II. EXECUTIVE SUMMARY

The VSCC is pleased to submit its comments on the Commission's proposed SMD, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55452 (2002) (to be codified at 18 C.F.R. pt. 35) (proposed July 31, 2002) ("SMD NOPR").

The VSCC would note at the outset, however, that while comments have been submitted on several key components of the SMD NOPR, the VSCC concludes that both in concept and execution, the proposed rules are fundamentally flawed, and should be withdrawn by the Commission in favor of a thorough examination of the critical issues encompassed by them. Such a review should fully consider state and federal jurisdictional questions, as well as the costs and benefits associated with implementing the sweeping interposition of federal control over the nation's electricity system envisioned in this rulemaking. A second look and perhaps even more is required.

Failing that, the VSCC respectfully requests the Commission to suspend its proceedings in this docket until it receives all necessary authority from Congress, and then to make the suggested changes described below to its NOPR before issuing any Final Rule herein.

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2 Letter comments of Commissioner Hullihen Williams Moore.

3 Letter comments regarding the optimal allocation of regional transmission organization ("RTO") characteristics and functions between RTOs and independent transmission companies ("ITCs"), submitted with the Virginia State Corporation Commission's and Indiana Utility Regulatory Commission's Recommended Division of RTO Functional Responsibilities.

4 Letter comments regarding the regarding the Commission's "Working Paper on Standardized Transmission Service and Wholesale Electric Market Design."

5 Letter comments regarding the Commission's "Options for Resolving Rate and Transition Issues in Standardized Transmission Service and Wholesale Electric Market Design" (the "Options Paper").

Here is a brief summary of the VSCC's comments on several of the critical issues contained in the NOPR:

Need for Reform.

The NOPR fails to distinguish between actions of incumbent utilities that might constitute undue discrimination, and those actions that manifest utilities' state law obligations to reliably serve native load customers. The NOPR provides anecdotal examples of "discrimination" on the part of transmission-owning utilities in support of its proposed SMD solutions. While there may be instances where incumbent utilities may have acted in a discriminatory manner, many of the alleged "discriminatory" acts—particularly those associated with retail transmission—can alternately be viewed as manifestations of utilities' state law obligations to reliably serve native load customers that have paid for those same facilities at reasonable costs. The NOPR seems to ignore this key backdrop, making no distinction between "due" and "undue" discrimination and branding all "preferences" as "undue" discrimination that must be eliminated. In doing so, the Commission has substituted questionable new preferences for existing appropriate preferences. A clear example of this is the proposed elimination of access charges for wheel throughs and wheel outs, while affording these transactions the same scheduling priority as other transactions that are subject to these access charges.

The NOPR also asserts that additional transmission facilities are needed to support robust wholesale competition. But the measures that the Commission proposes to incent transmission construction may not in fact do so, and might even discourage transmission solutions. Rate incentives that are not carefully targeted to foster the building of new transmission would merely provide an economic windfall to the recipients. Utilities that pursued flawed business strategies should not be insulated through "incentives" from the financial consequences of their past behavior. Moreover, transmission expansion pricing mechanisms intended to send "price signals" do not in and of themselves resolve the difficult environmental and land use issues associated with new transmission facilities. Hence, sending such LMP-based price signals to those customers in transmission-constrained areas could expose them to the worst of both worlds: ever-increasing congestion charges, without the ability to act to avoid such charges.

Placing Bundled Retail Customers Under the Interim Tariff.

The FERC should not extend the SMD's coverage involuntarily to those states that have not chosen retail access, or to states that have either acted or are acting to suspend retail access programs. A key component of the NOPR is the Commission's decision to bring bundled retail transmission service within the SMD's scope and operation. The Commission states that its authority over bundled retail transmission service arises, in large part, from the U.S. Supreme Court's decision in New York v. Federal Energy Regulatory Commission, 535 U.S. __, 122 S. Ct. 1012 (2002) ("New York" or "New York v. FERC"). In that decision the Supreme Court upheld the Commission's application of its open access transmission requirements in Order No. 888 to unbundled retail service. The Commission declares in its NOPR, however, that the Supreme Court also concluded "that the Commission had jurisdiction over transmission used for *bundled* retail sales of electric energy in interstate commerce." SMD NOPR at 55468, para. 102.[6]

The Commission's assertion of jurisdiction over bundled retail transmission service has generated vigorous opposition from many of Virginia's sister states, including North Carolina, Florida and other Southeastern states. These are states that have not yet adopted state retail choice plans either through legislation or otherwise. Consequently,

[6] As discussed later in the VSCC's comments, however, the NOPR goes far beyond the Commission's assertion of jurisdiction over the retail transmission piece of bundled rates. In fact, the NOPR effectively asserts Commission authority over generation pricing and reliability—historically, and statutorily, matters long under the authority of states and their regulatory commissions. Such an attempted shift in authority conflicts with § 201(b) of the Federal Power Act which provides, in pertinent part, that the FERC "shall have jurisdiction over all facilities for such transmission or sale of electric energy, but *shall not* have jurisdiction… over facilities used for the generation of electric energy…." (emphasis added).

they are representative of those states whose retail electric rates are not unbundled. Yet, the many and far-reaching components of the proposed SMD would nevertheless be applied to such states and their utilities.

In the Commonwealth of Virginia, the General Assembly acted in 1999 to inaugurate competition for retail generation—or at least to extend an invitation to competitive suppliers. Since its enactment in 1999, the provisions of the Virginia Electric Utility Restructuring Act ("Restructuring Act") have been the subject of continuing consideration, debate, and modification. Implementation efforts have been considerable and will continue for years to come.

Moreover, while virtually the entire state is open to retail access as of January 1, 2003 (with the exception of most cooperatives and one investor-owned utility serving fewer than 30,000 customers in western Virginia), there are presently no competitive offers being marketed for alternatives to capped rate service provided by incumbent utilities. The VSCC would also note that the number of Virginia retail electric customers taking service from alternative suppliers are at last count about 2,300, nearly all of whom take supply under a "green power" offer priced above the incumbents' capped rate service. Stated simply, Virginia's transition to a competitive market remains in its infancy.

The VSCC believes that the sweeping jurisdictional assertions of the SMD NOPR are problematic enough for those states such as Virginia that are transitioning between traditional cost-of-service regulation and competitive retail generation access, as discussed above. Thus, in the VSCC's view, the FERC should not, extend the SMD's coverage *involuntarily* to those states that have not chosen retail access, or to states that have either acted or are acting to suspend retail access programs. The VSCC believes that the spirit of Order No. 2000—one of voluntarism—should not be abandoned in the effort not so much to "get it right" but to "get it done."

The New Transmission Service: Load Shedding and Curtailments.

Load shedding and system usage reductions are state/local matters; ITPs should not tell specific transmission customers how to do either. Congestion Revenue Rights should be purely financial instruments with no associated preferred scheduling or curtailment rights. As a purely operational matter, it makes sense for the ITP, when faced with an unanticipated system emergency in real time, to identify as quickly as possible those system transactions that are contributing to the contingency or that can relieve it, and to cut those transactions *pro rata.* The ITP, however, should not tell specific transmission customers how they should shed load or otherwise reduce their system usage; this is a state/local matter. Part II.B., Section 9.4 of the proposed SMD Tariff should be clarified accordingly. SMD NOPR at 55547. If the ITP has the opportunity to pick and choose among the transmission customers it will curtail, it should curtail first through-and-out customers (who will not pay ITP transmission fixed transmission costs) and then curtail *pro rata* the transactions of Load Serving Entities ("LSEs") serving loads in the ITP's footprint. Congestion Revenue Rights ("CRRs") should not invest the holder with any preferred scheduling or curtailment rights; they should be purely financial instruments.

Transmission Pricing.

Customers paying ITPs' fixed transmission costs should receive higher quality transmission service than those transmission customers not allocated a share of those costs. If through-and-out transmission customers are not going to be allocated a share of the ITP's fixed transmission costs, then those transmission customers paying such costs (those customers sinking load on the ITP's system) should be entitled to a higher quality transmission service. They should have: (1) priority allocation of CRRs; and (2) a physical curtailment priority if the ITP cannot honor all transmission schedules after application of its LMP-based congestion management scheme.

Locational Marginal Pricing.

Locational Marginal Pricing ("LMP") should not be adopted in any region unless and until a thorough analysis of its likely effects on the retail electric customers in that region is completed and fully considered. LMP should not be implemented if such an analysis shows that LMP will result in (i) substantial cost increases, or (ii) the exercise of market power that could adversely affect power markets. The VSCC is familiar with the operation of Locational Marginal Price ("LMP")-based congestion management schemes because some regions of Virginia are now part of PJM or PJM West. The VSCC believes that a "flash cut" to LMP in regions in which it is not now being used is problematic because:

- It requires this Commission to assert control over generation facilities, which is beyond the Commission's jurisdiction under FPA Section 201(b)(1).
- Use of LMP can dramatically increase power supply costs for municipalities, cooperatives, and other LSEs that do not have their own assured supply of generation.
- Implementation of LMP effectively ends the cost-based, average rate regime historically used to provide retail electric service, and can therefore lead to very substantial cost increases in areas with constrained transmission and/or higher cost generation.
- LMP in actual practice may not provide the "right" economic incentives to transmission customers when all pertinent factors, price and non-price, are considered.
- Unless the ITP's Day Ahead ("DA") market is either perfectly competitive or thoroughly mitigated, an LMP-based congestion management scheme can unintentionally serve as a vehicle for price manipulation and market power abuse, making effective market power monitoring and mitigation an absolute necessity.

For these reasons, LMP should not be adopted in a region without careful consideration to its likely effects on the retail electric customers in those regions. If analysis shows that a region's transmission and generation infrastructure is insufficient to support a move to LMP without substantial cost increases, or that market power exercise could adversely affect power markets in the ITP's region, then LMP should not be implemented until these problems are resolved.

Congestion Revenue Rights.

CRRs should be allocated to LSEs serving loads in the ITP's footprint and paying the ITP's fixed transmission costs, both as an initial matter when LMP is first implemented and continuing on an annual basis thereafter. Such allocations should account for load growth. Continuing, periodic allocations of CRRs to LSEs will allow them to better hedge their transmission transactions, and minimize the possibility that other entities might speculate in CRRs, hence increasing congestion costs that must be passed through to retail customers. Secondary auctions of CRRs that LSEs choose to resell and of excess CRRs left over after the periodic allocation of CRRs to LSEs would enable other market participants to obtain CRRs, with less concern about manipulation of CRR auctions.

Day-Ahead and Real-Time Markets.

The Commission must ensure that the SMD Tariff's "best practices" provisions for Day Ahead ("DA") and Real-Time ("RT") energy and ancillary services are cohesive, and that individual ITPs have the flexibility to implement energy markets first and ancillary services later. The Commission's SMD tariff sets out "best practices" for Day Ahead ("DA") and Real-Time ("RT") energy and ancillary services markets. In taking provisions from a number of different tariffs and schemes to draft its SMD Tariff, however, the Commission must be careful not to create a "Frankenstein" DA/RT market regime. The Commission should allow individual ITPs (especially "greenfield" ITPs) the option to implement energy markets first, and ancillary services markets at a later time.

Capacity Benefit Margin.

Capacity Benefit Margins ("CBM") have a legitimate role to play in assuring reliable service to retail electric customers, and should not be totally eliminated. Instead, the ITP should, based on its knowledge of the long-term resources of all the LSEs serving loads in its footprint, independently develop the amount of CBM required to ensure reliable service to loads within its footprint, and assess all LSEs in its footprint for the associated fixed costs.

Regional Planning Process.

The Commission should not require the institution of the proposed regional transmission planning process, including MSEs, without further exploring the need for such entities and more clearly delineating their structure, authority, and responsibilities. The NOPR proposes that long-standing state authority over approval and siting of new transmission facilities be supplanted by regional transmission infrastructure planning conducted by Multi-State Entities ("MSEs"). States would be relegated to the role of committee members in these regional planning entities. All public utilities owning transmission must participate in a planning area from the outset with the ITPs becoming progressively part of the process. The NOPR suggests that planning areas could be made up of multiple existing ISOs or RTOs; thus, planning areas are intended to include multiple regional markets.

The VSCC is concerned that the approach taken by the NOPR ignores current regional market planning, as well as states' authority over approval and siting of transmission facilities. The NOPR does not demonstrate why the proposed regional planning areas, which, as proposed, may span large geographic areas and consist of multiple regional markets, will be the best means to meet the needed transmission infrastructure goals.

Thus, the VSCC recommends that the Commission not require the institution of the proposed regional planning process, including the MSEs, without further exploring the need therefore, and clarifying the structure and authority of such entities.

Market Power Mitigation and Monitoring.

Market Monitors must be fully independent of ITPs' management (including ITP Boards), and must be given sufficient resources to do their jobs, including a full array of mitigation tools to deal with suspicious bidding behavior.

The potential for market manipulation and market power abuse under the proposed SMD is very high. Hence, without a strong and fully independent Market Monitor ("MM") and modifications to a number of the NOPR's provisions, SMD could well fail. MMs should be fully independent of ITP managements (including ITP Boards), and should be given sufficient resources to do their jobs, without the need to take on other consulting assignments. They should be chosen by a broad stakeholder group, rather than by ITPs and TOs alone. They should not be able to be removed prior to contract termination without good cause and prior Commission approval. The MM's reports should be widely disseminated to all interested parties (consistent with confidentiality provisions).

MMs should monitor regional bilateral markets and mitigate transactions in those markets if necessary to prevent the exercise of market power. It is the bilateral market the Commission intends for LSEs to look to in contracting to meet their RAR obligations; hence, mitigation in the ITPs' spot markets alone will not prevent the exercise of generation market power. LSEs will have to procure power supplies in the bilateral market to comply with the RAR requirement, and sellers of generation will be well aware of this fact and exploit it if possible to the detriment of LSEs and their retail customers.

MMs should also have access to the data they require to monitor transactions in all markets in the ITP's region, including data from market participants and from the ITP itself. Confidentiality concerns can be dealt with through appropriate protections.

The Commission should require public utility sellers of power into the ITP's markets to show that they should be permitted to charge market-based rates in the first instance. The great bulk of public utility sellers of power hold market-based rate authority granted under the now discredited "hub and spoke" test. The Commission and the regional MMs should therefore conduct an in-depth structural assessment of each regional power market and the public utility sellers in those markets to ensure that only those without market power are granted continuing authority to sell power at market-based rates. Particular generation units that do enjoy local market power due to their unique locations or operating characteristics can then be dealt with through price mitigation in a specific Participating Generator Agreement ("PGA"). MMs should have a full array of mitigation tools available to them to deal with suspicious bidding behavior.

Long-Term Resource Adequacy.

The NOPR's provisions assigning generation resource adequacy to FERC-regulated ITPs would effectively supplant long-standing state authority over generation supply adequacy. The VSCC is unable to determine FERC's jurisdictional basis for doing so under the Federal Power Act; nor is it clear that the resource adequacy requirement can be practically applied in a retail access state such as Virginia.

The NOPR assigns the responsibility for assuring generation resource adequacy to ITPs. In doing so, the NOPR seeks to regionalize (and thus federalize) requirements that have generally fallen under state purview through state law. Stated simply, the adequacy of generation supply to meet current and future needs is an issue charged with overwhelming state interest; it affects the health, welfare and economic well being of this Commonwealth and its citizens.

The NOPR proposes that ITPs provide a forecast of the demand in their areas, help the Regional State Advisory Committee ("RSAC") determine future reserve requirements, and assign each LSE a share of the needed future resources. The NOPR's resource adequacy proposal leaves many important questions unanswered. Specifically, the VSCC questions the practical application of the requirement in a retail access environment. Nor is it clear that the NOPR makes allowance for *any* state-imposed reserve requirements—or whether it would matter even if it did. Consequently, it appears that an LSE satisfying a more rigorous state requirement would have no additional priority and would have to share those resources across its designated region. Thus, under the NOPR a state-mandated higher reserve requirement would provide few or no additional reliability-related benefits to the state or its citizens.

Moreover, it is not at all clear that the Commission has any authority under the Federal Power Act ("FPA") to shift oversight of resource adequacy to the ITP, a regional entity under the regulation of the Commission. In such a regime, states' authority over generation resources would be diminished to their participation in regional advisory committees. Section 201(b) of the FPA states that the FERC "shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction… over facilities used for the generation of electric energy…." As such, the express language of the FPA runs counter to the Commission's proposal to shift oversight of resource adequacy to ITPs.

State Participation in RTO Operations.

RSAC participation by the VSCC may conflict with role assigned by the Virginia General Assembly to the VSCC concerning the restructuring of Virginia's retail electricity market. The NOPR provides that various RSACs will be formed in order that states may have a "formal" role in the SMD decision-making process. Issues identified in the NOPR to be resolved by the RSACs are: 1) Resource adequacy standards; 2) Transmission planning and expansion; 3) Rate design and revenue requirements; 4)

Market Power and market monitoring; 5) Demand response and load management; 6) Distributed generation and interconnection policies; 7) Energy efficiency and environmental issues; and 8) RTO management and budget review. The role of states within the RSACs is limited to their voting power along with that of other regional participants.

The VSCC has concerns as well about its lawful participation in RSACs. Under the Constitution and laws of Virginia, the VSCC must perform specific regulatory functions. Because the NOPR indicates that RSACs will decide issues of state and concurrent jurisdiction, based on "regional" goals, it is not clear that the VSCC could lawfully participate in any such organization.

Specifically, the VSCC has a continuing duty imposed by Virginia's restructuring legislation to advance competition and economic development in this Commonwealth in conjunction with all actions its takes under the aegis of restructuring. Obviously, an RSAC's perspective would be regional, and not focused solely on the well being of Virginia and its citizens. Additionally, Virginia's restructuring law assigns to a legislative oversight body (the Legislative Transition Task Force), the obligation of working collaboratively with the VSCC concerning the phase-in of retail competition within the Commonwealth. Clearly, RSAC participation by the VSCC could easily conflict with the collaborative relationship between the Virginia General Assembly and the VSCC concerning the restructuring of Virginia retail electricity market.

To its credit, the Commission is seeking ways for the states to interact with regional transmission entities. However, the regional advisory committee vehicle does not appear to be the best way to provide solutions for issues of state and concurrent jurisdiction. At a minimum, further clarification as to the purpose, authority and structure of the RSACs is needed before states can provide any meaningful input as to the appropriateness of this significant element of the NOPR.

Governance for Independent Transmission Providers.

ITPs must be given sufficient powers over the transmission facilities and operations turned over to its control to permit it to operate these facilities in a fully independent fashion. The VSCC agrees that ITP independence is critical to the successful implementation of SMD. The VSCC also agrees that an ITP's board should be independent from all market participants, but suggests that some flexibility in how this goal is accomplished may be appropriate. The VSCC for its part is most concerned that the ITP be given sufficient powers over the transmission facilities and operations turned over to its control to permit it to operate these facilities in a fully independent fashion. The ITP must control all needed transmission facilities, and have sufficient operational authorities over those transmission facilities (including operations, planning and expansion and reliability assurance).

III. COMMENTS

A. Need for Reform

The NOPR provides anecdotal examples of discrimination in support of its proposed SMD solutions. While the VSCC does not doubt that there are instances where incumbent utilities may have acted in a discriminatory manner, many of the alleged "discriminatory" acts can alternately be viewed as manifestations of the traditional mandates, generally imposed on utilities by state law, to reliably serve native load at reasonable costs.[7] In fulfilling this mandate, incumbent utilities under the oversight of state regulatory commissions have consciously made trade-offs between generation and transmission. Most utilities have sought to meet their customers' needs by the most economical means, whether it is through investment in new transmission, new generation resources or load management. Under this paradigm, generation and transmission have

[7] The Virginia General Assembly, for example, has declared that it is the duty of every public utility in the Commonwealth to furnish "reasonably adequate service and facilities at reasonable and just rates to any person, firm or corporation along its line desiring same." Section 56-234 of the Code of Virginia.

been, to a large extent, interchangeable. As such, many of the alleged examples of discrimination are simply instances where facilities have been utilized to serve native load customers that have paid for those same facilities. The reservation of Available Transfer Capability ("ATC") for native load growth and the withholding of transmission capacity associated with Capacity Benefit Margin ("CBM") are clear examples of legitimate actions undertaken in the interest of customers (both wholesale and retail) that have borne the lion's share of the costs of transmission facilities.

The NOPR simply ignores this key backdrop and utilizes these alleged instances of "discrimination" to justify extension of the Commission's jurisdiction far beyond its historical and statutory bounds. The Commission appears to make no distinction between "due" and "undue" discrimination and brands all "preferences" as "undue" discrimination that must be eliminated. In doing so, the Commission has substituted questionable new preferences for existing appropriate preferences. A clear example of this is the proposed elimination of access charges for wheel throughs and wheel outs, while affording these transactions the same scheduling priority as other transactions that are subject to these access charges.

The NOPR asserts that additional transmission facilities are needed if we are to have robust wholesale competition. The NOPR proposes a number of radical and complex measures designed in large part to incent the construction of new facilities without, however, addressing the actual obstacles to new transmission facilities. The VSCC believes that certain of these "solutions" may actually act to discourage new transmission solutions rather than to encourage them.

The VSCC has considerable experience in the review and approval of new transmission lines. Its experience in transmission line siting has been that the largest obstacle to such construction is not need or even lack of appropriate incentives but land use and environmental issues, particularly where such facilities impact federal lands.[8] While the need to obtain state and local approvals for new transmission facilities has often been cited as a major obstacle to new transmission projects, in fact obtaining needed approvals from the federal government can prove to be even more difficult, as Virginia's own experience bears out. Most land use and environmental issues are contentious and difficult to resolve. This is most critically evident when those who bear the environmental and esthetic costs of such facilities will not reap, or do not believe they will reap, any benefit from construction of these facilities. Rural landowners and businesses bitterly resent any disturbance of their local view-sheds, woodlands, and farmlands that provide advantages only for distant cities. The Commission's SMD proposal neither addresses nor proposes resolution to these basic matters.

One of the systemic problems that the Commission must address if it is to construct a sound regional transmission platform for wholesale power markets is transmission system expansion. The Commission must look past the rhetoric and

8 Greater coordination among the Commission, the states, and RTOs in and of itself may not always "speed up" the siting process. For example, on May 31, 2001, the VSCC issued an order in Case No. PUE-1997-00766, Application of Appalachian Power Company, For certificates of public convenience and necessity authorizing transmission lines in the Counties of Bland, Botetourt, Craig, Giles, Montgomery, Roanoke and Tazewell: Wyoming-Cloverdale 765 kV Transmission Line and Cloverdale 500 kV Bus Extension, 2001 S.C.C. Ann. Rept. 366, The VSCC issued an order approving the Appalachian Power Company's (an AEP operating company) ("AEP-Virginia") proposal to construct a major transmission line from West Virginia into Virginia. A 1991 proposal to construct a similar line was withdrawn by the Company due to routing difficulties associated with federal approvals. The Company identified two developments that led it to withdraw the 1991 application and to file a second application using another route. First, AEP-Virginia stated that subsequent to their filing for the proposed line Congress directed a study of a segment of the New River for possible addition to the National Wild and Scenic River System. The route proposed in the 1991 case would have crossed the New River in the segment under study, and the Company determined that the crossing was foreclosed. In addition, the U.S. Forest Service and other federal agencies released on June 18, 1996, a draft environmental impact statement addressing the 1991 route. Preparation of the draft statement was part of the process of approving the crossing of federal lands and the New River. The draft statement raised a number of issues and clearly signaled that the proposed route through federal lands would not be approved. These developments led AEP-Virginia to reconsider the 1991 project. The revised route approved by the VSCC in early 2001 only recently received approval (December, 2002) from the U.S. Forest Service.

consider what policy initiatives would in fact encourage the development of a robust and rational regional transmission system. This does not mean simply "throwing money at the problem" through the use of rate "incentives." Many FERC-regulated public utilities have in recent years viewed their regulated utility operations, including the provision of transmission service, as a generator of cash to be spent pursuing mergers, wholesale merchant/energy trading activities and other unregulated ventures (from home security companies to generation ventures on other continents). Some embarked upon flawed business plans that have now come home to roost.[9] Providing incentives in the form of higher rates of return, levelized rates and other such untargeted "rate goodies" would only reward such utilities for their past behavior by effectively insulating them from the consequences of their own actions. While the VSCC is not opposed to reasonable economic incentives that would in fact foster the building of necessary new transmission facilities, any such incentives should be carefully designed to reward the desired behavior and results, and not merely to provide an economic windfall.[10] The VSCC would support efforts to develop targeted rate incentives tied directly to the financing of new transmission facilities needed to maintain or enhance reliability or to eliminate

9 See, e.g., Outlook 2003: U.S. Power & Gas, Fitch Ratings, December 17, 2002 (available at <http://www.fitchratings.com>) at 1 ("The outlook for the U.S. power and gas industry has increasingly polarized between the stable outlook for those regulated distributors and integrated utilities which do not have significant merchant energy activities, including public power entities; and the negative outlook for those companies that are major participants in wholesale, merchant power and gas markets, or whose affiliates/parents have large exposure.").

10 It is important to study closely the question of what rate incentives are in fact required to call forth the necessary transmission investment, or the Commission might needlessly give away ratepayer dollars. In doing so, the Commission should consider the testimony given before the House Commerce Committee's Subcommittee on Energy and Power on July 27, 2001, by Thomas Lane, Managing Director of Goldman Sachs and Company. Under questioning from Rep. Richard Burr (R-NC) as to the return that would be required to attract investors to put money in transmission-related investment vehicles, Mr. Lane stated: "There is definitely a role in the markets for a lower risk, lower return investment which is what transmission represents. Whether it is in the 11 percent-12 percent, somewhere in that neighborhood is what we still need to ferret out with the investor base." If 11-12 % was considered a feasible return by Mr. Lane for transmission-related investments in 2001, then that range could only have gone *down*, not *up*, since that time, given the deterioration of the stock market during the intervening period.

significant, continuing transmission congestion if it is clear that such incentives are necessary to provide the intended benefits.[11]

The Commission finds in SMD NOPR that "proper price signals are not being sent to the marketplace, with the result that . . . reasonably accurate price signals necessary for infrastructure additions are not being sent." Id. at 55468, para. 105(4). The Commission proposes a regional planning process at paras. 335-350, which it describes as "fully consistent with Standard Market Design's goal of inducing efficient investment by relying primarily on price signals and independently administered Congestion Revenue Rights." Id. at 55498, para. 350. But the VSCC is concerned that a transmission planning mechanism that relies primarily on "price signals" might not in fact get needed transmission facilities built.

The VSCC also must question whether the SMD NOPR in fact sends the right price signals regarding transmission expansion. The Commission states that its "preference is to allow recovery of the costs of expansion through participant funding, i.e., those who benefit from a particular project (such as a generator building to export power or load building to reduce congestion) pay for it." SMD NOPR at 55479, para. 197. In principle, the VSCC does not oppose the concept of requiring those who benefit from a particular project to pay for it. In analyzing potential network upgrades or additions to a transmission system, however, the issue of precisely *who* benefits is often not at all clear. Network upgrades may indeed benefit the proponent of a particular generation project or, for example, a particular Load Serving Entity ("LSE") that requests a new resource designation, thus triggering a facilities study request. But due to the interconnected nature of the transmission grid, these very same network upgrades could also benefit many other loads in the transmission provider's region. In such

[11] It must be remembered that an appropriate return is one that allows the utility to pay its bills and have a return sufficient to attract capital. If the return does this, that is attracts capital, no additional "incentive" is needed.

circumstances, assigning 100% of the associated upgrade costs to the entity that happened to request a particular service may not be appropriate.[12]

Such a funding regime does not in the VSCC's view provide rational financial incentives for customers to fund transmission expansions. Instead, it seems to promote a "tag, you're it" approach to transmission system expansion funding that would make transmission customers hesitate to request new service, for fear that they may be tagged with the full brunt of the cost of transmission facilities that would benefit many others besides them. There is no easy solution for this problem, largely because at issue are facilities that are not, or may be only partially, necessary for reliability, but rather are needed to give competition an opportunity to function effectively.

The Commission must first recognize overarching land-use and environmental issues-- both those that are under state and local regulation as well as those administered by other federal agencies and get the financial incentives right if it truly wishes to see new transmission facilities constructed. In the absence of new transmission construction, the introduction of locational marginal pricing ("LMP") could result in the worst of both worlds: levying of ever-increasing congestion charges for the use of constrained transmission facilities, with the accompanying inability of LSEs and end users to take actions sufficient to avoid these increased charges. A price signal does little if it cannot

[12] The Commission proposes to allocate Congestion Revenue Rights ("CRRs") to those entities funding network transmission upgrades or expansions. P. 238. It also asks whether there is still a role for credits for upgrades (giving transmission customers a credit on its transmission service bill for the cost of network upgrades it previously financed) if such a CRR allotment is provided. Id. But CRRs only entitle customers holding them to congestion revenues in the event of congestion, which may be substantially reduced or even eliminated due to the construction of the new transmission facilities. In fact, it is not inconceivable that if the CRRs given to the customer are obligations (rather than options), the customer may in fact have to *pay out* congestion revenues for the privilege of holding the CRRs, on top of having paid for the expansion itself. See SMD NOPR at 55485, para. 245.

be adequately responded to through construction of needed new facilities or demand response.[13]

In short, the VSCC believes that the proposed "solutions" are ineffective and that the Commission has failed to justify the need for such radical reform.

B. The Interim Tariff: Placing Bundled Retail Customers under the Interim Tariff

A key component of the NOPR is the Commission's decision to bring bundled retail transmission service within the SMD's scope and operation. Finding that "undue discrimination and anticompetitive behavior persist" in both wholesale and retail transmission of energy, the Commission asserts that "[A]t a minimum, *all* transmission service in interstate commerce must be subject to the same non-discriminatory, non-rate terms and conditions in order to eliminate undue discrimination in wholesale markets and *retail choice markets.* With respect to rates for bundled retail transmission service, we will work with states to address difficult transition rate issues." (Emphasis added.) SMD NOPR at 55468, paras. 102-103. Accordingly, the Commission proposes that the transmission component of bundled retail service be taken under an open access transmission tariff, and that in the interim bundled retail load be placed under existing pro forma tariffs. Id. at 55470, paras. 118-120.

The Commission states that its authority over bundled retail transmission service arises, in large part, from the U.S. Supreme Court's decision in New York v. Federal Energy Regulatory Commission, 535 U.S. ___, 122 S. Ct. 1012 (2002) ("New York" or "New York v. FERC"). In that decision the Supreme Court upheld this Commission's

[13] It should be noted that the vast majority of retail customers are unlikely to see LMP pricing directly and will likely see some average of such prices over some extended period of time.

application of its open access transmission requirements in Order No. 888 to unbundled retail service. The Commission declares in its NOPR, however, that the Supreme Court also concluded "that the Commission had jurisdiction over transmission used for *bundled* retail sales of electric energy in interstate commerce." SMD NOPR at 55468, para. 102.[14]

The Commission's assertion of jurisdiction over bundled retail transmission service has generated vigorous opposition from many of Virginia's sister states, including North Carolina, Florida and other Southeastern states. These are states that have not yet adopted state retail choice plans either through legislation or otherwise. Consequently, they are representative of those states whose retail electric rates are not unbundled. Yet, the many and far-reaching components of the proposed SMD would nevertheless be applied to such states and their utilities.

Early filings made in this docket by North Carolina and Florida are at the heart and heat of opposition to the mandatory imposition of the SMD to those states that, to date, have not chosen a market-driven approach to electric rates within their jurisdictions. North Carolina, for example, emphatically challenges this proposed expansion of the Commission's jurisdiction, asserting, *inter alia,* that neither the language nor legislative history of the Federal Power Act would support this Commission's claim to jurisdiction over bundled retail transmission.[15] Moreover, the North Carolina filing declares, the

[14] The NOPR goes far beyond the Commission's assertion of jurisdiction over the retail transmission piece of bundled rates, however. In fact, the NOPR effectively asserts FERC authority over generation adequacy, pricing and reliability—historically, and statutorily, matters long under the authority of states and their regulatory commissions. Such an attempted shift in authority conflicts with § 201(b) of the Federal Power Act which provides, in pertinent part, that the Commission "shall have jurisdiction over all facilities for such transmission or sale of electric energy, but *shall not* have jurisdiction… over facilities used for the generation of electric energy…." (emphasis added). Moreover, while the U.S. Supreme Court in *New York v. FERC*, may have suggested that the Commission's authority under § 206 of the FPA might (upon proper findings) be invoked to remedy "undue discrimination" in the retail electricity through the Commission's regulation of bundled retail transmission, nothing in that opinion can be read as signaling Commission authority to eviscerate vital state authority over the pricing, reliability and adequacy of generation resources.

[15] Comments of the North Carolina Utilities Commission, Public Staff-North Carolina Utilities Commission, and the Attorney General of the State of North Carolina, Docket No. RM01-12-000 (November 15, 2002) ("North Carolina Comments"), at 13.

Commission's description of legal authority for this jurisdiction in Paragraph 102 of the NOPR misinterprets the Supreme Court's opinion in New York.[16]

Similarly, the comments of the Florida Public Service Commission filing vividly illustrates the depth of opposition to the Commission's efforts to apply the standard market design to those states with bundled retail rates, and no retail access programs.[17] The Florida Comments emphasize that Florida supported the Commission's assertion of authority under Order No. 888 over unbundled retail transmission, and also that Florida supports Order No. 2000's emphasis on voluntary participation by state utilities in regional transmission organizations.[18] Florida's Commission goes on to state that it has been instrumental in promoting the development of GridFlorida, whose development has been slowed by the presence of a market design somewhat at variance with that envisioned in the NOPR.

In the Florida Commission's view, the requirements in the NOPR (i) exceed the Commission's authority, (ii) jeopardize the voluntary progress concerning regional transmission organizations that has been made, and (iii) result in an attempted preemption of state authority that precludes the Florida Commission's obligations to protect its retail ratepayers. Underscoring these points, the Florida Commission takes issue with the Commission's assertions that utilities' preferential treatment of their native load retail customers, *ipso facto*, constitutes discrimination. The Florida Commission asserts that native load *should* have preferential access to the transmission system that was built to serve it.[19]

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16 North Carolina Comments at 16.

17 Comments of the Public Service Commission of the State of Florida, Docket No. RM01-12-000 (October 28, 2002) ("Florida Comments").

18 Florida Comments at 2.

19 Id. at 10.

In particular the Florida Commission said "[T]his is not an argument to allow 'undue' discrimination on the part of vertically integrated utilities, but a recognition of appropriate levels of priority access to the existing grid with respect to *obligations to serve, system reliability, and allocation of system resources. These are essential and vital areas of state jurisdiction and are essential elements for the provision of bundled, retail electric service*." (Emphasis added.). Florida Comments at 10.

The VSCC wholeheartedly agrees with the Florida Commission that "*obligations to serve, system reliability, and allocation of system resources"* are vital to *any* consideration of transmission grid access. In such states as Florida and North Carolina that have not adopted retail competition plans and in other states where competition continues to be a "work-in-progress", it is to those states' regulatory commissions and not "the market" that millions of retail customers look to ensure that the lights stay on. Thus, it is easy to understand that in such states, a federalized, standard market design blithely anticipating that, among other things, needed generation and transmission will be constructed when the prices get high enough, does not offer much peace of mind.

In the Commonwealth of Virginia, the General Assembly acted in 1999 to inaugurate competition for retail generation—or at least to extend an invitation to competitive suppliers.[20] Since its enactment in 1999, the provisions of the Virginia Electric Utility Restructuring Act, § 56-576 et seq. of the Code of Virginia ("Va. Code") ("Restructuring Act") have been the subject of continuing consideration, debate, and modification. Implementation efforts have been considerable and will continue for years to come. Thus, Virginia is a retail access state with unbundled rates. However, Virginia's transition to retail competition for electric generation will not be completed until July 1, 2007. Until then, Virginia's retail electricity customers are entitled to the protection of capped rates mandated pursuant to § 56-582 of the Restructuring Act.

[20] Senate Bill 1269 enacted by the 1999 Session of the Virginia General Assembly, codified as Chapter 23 (§ 56-576 et seq.) of Title 56 of the Code of Virginia.

Moreover, while virtually the entire state is open to retail access as of January 1, 2003 (with the exception of most cooperatives and one investor-owned utility serving fewer than 30,000 customers in western Virginia), there are presently no competitive offers being marketed for alternatives to capped rate service provided by incumbent utilities. The VSCC would also note that the number of Virginia retail electric customers taking service from alternative suppliers is at last about 2,300, nearly all of whom take supply under a "green power" offer priced above the incumbents' capped rate service.

Thus, at present, Virginia is a retail choice state in name only, with all but a minute fraction of its retail electric service furnished by utilities that remain and operate vertically integrated. A competitive market for retail generation has not developed within the Commonwealth, nor is one visible in the region, either. Given these circumstances, Virginia presently has more in common with states like North Carolina and Florida—states without retail choice plans—than states such as Pennsylvania and New Jersey whose retail choice plans are more mature, albeit not much more successful in developing a *bona fide* competitive market for retail generation supply.

States like Virginia that are in transition to becoming "retail choice markets," view their restructuring laws as individual paths to competitive markets—a legislative market design that in Virginia's case was three years in the making, and continues to be revised under the oversight of its legislative transition task force, with input from the VSCC and stakeholders.

Consequently, the SMD's top-down approach to the development of competitive wholesale markets, sweeps state retail restructuring plans to the margins. In Virginia, for example, § 56-579 of the Restructuring Act requires the VSCC to determine whether the public interest will be served by the transfer of this Commonwealth's transmission assets to regional transmission entities. The SMD, however, takes enormous liberties with the Federal Power Act by insisting that these transmission assets come under the

Commission's control, irrespective of what Virginia's General Assembly may have had in mind.

The VSCC believes that the sweeping jurisdictional assertions of the SMD NOPR are problematic enough for those states such as Virginia that are transitioning between traditional cost-of-service regulation and competitive retail generation access, as discussed above. Virginia's legislators could hardly have guessed in 1999 that requiring rate unbundling simply for the sake of calculating "prices to compare" and competitive transition charges for shopping customers would make the reliability and resource adequacy oversight of Virginia's generation vulnerable to a federal scheme several years later that would severely erode the state's ability to ensure reliable electric service.

In his concurrence and dissent in New York, Justice Thomas argues that states should not be permitted to determine FERC jurisdiction by whether they bundle or unbundle their electric rates, as if to suggest that doing so requires nothing more than a casual bookkeeping entry or two. Virginia's incumbent electric utilities can testify to the enormous commitment of human and financial resources required by the unbundling process, as well as all of the other processes required to implement and continue the Commonwealth's transition to retail choice. It is no small step; it is a commitment to abandon conventional regulatory ratemaking and protections, and to place total confidence in an untested and unpredictable market.

Thus, in the view of the VSCC, the FERC should not extend the SMD's coverage involuntarily to those states that have not chosen retail access, or to states that have either acted or are acting to suspend retail access programs. The VSCC believes that the spirit of Order No. 2000—one of voluntarism—should not be abandoned in the effort not so much to "get it right" but to "get it done."

C. The New Transmission Service: Load Shedding and Curtailments

LSEs Serving Loads Within the ITP's Footprint and Paying the ITP's Fixed Transmission Costs Through an Access Charge Should Receive Priority of Service During System Curtailments.

The Commission anticipates that the need for physical system curtailments (in the form of Transmission Line Loading Relief calls, or "TLRs") will be diminished through use of an LMP-based congestion management system. SMD NOPR at 55475, para. 158. The VSCC agrees that, in theory, this should be the case. The Commission, however, proposes to deal with any physical curtailments that the ITP might still find necessary to implement under SMD by curtailing "the customers whose transactions contribute to the constraint on a pro rata basis." Id. at 159. In addition, the Commission proposes that if the ITP is unable to schedule all requests for service made through the day-ahead scheduling process, "those customers with Congestion Revenue Rights for their requested receipt point-delivery point combinations should be scheduled first." Id. Both these proposals concern the VSCC, for the following reasons.

First, as a purely operational matter, it likely makes the most sense for the ITP, when faced with an unanticipated system emergency in real time, to identify as quickly as possible those transactions that are contributing to the contingency, and to cut these transactions *pro rata*. The VSCC, however, notes that the language of the proposed SMD Tariff on this point is unclear. Part II.B. Section 9.4 of the Proposed SMD Tariff set out in Appendix B (Page No. 60), entitled "Load Shedding," states that if it is necessary for the ITP to have transmission customers shed load to deal with a system contingency, the ITP is to direct transmission customers "to shed Load on a non-discriminatory basis to alleviate the Emergency/reliability contingencies." SMD NOPR at 55547. As drafted, this language appears to require *the respective transmission* *customers (including LSEs) to shed end use load on their own systems on a non-discriminatory basis.* This would be an unnecessary and *ultra vires* exercise of jurisdiction by the Commission over retail sales/local distribution matters properly left to the states under the FPA.[21] There may be very strong policy reasons for LSEs that must reduce their own transmission system usage in response to a transmission contingency to curtail certain of their own distribution customers first (for example, customers with back-up power arrangements or prearranged agreements with the LSE to shut down operations on request), rather than curtailing all of their retail customers on a *pro rata* basis. The VSCC therefore requests that if the Commission continues to go forward with the SMD, at a minimum, Section 9.4 should be revised to make clear that the ITP will not require transmission customers that are also LSEs to cut their own respective retail loads on a *pro rata* basis, but will leave this matter to the relevant state and local authorities.

Assuming *arguendo* that the ITP has the opportunity to pick and choose among the transmission customers it would curtail in the event of a transmission shortage, the VSCC would recommend that the ITP first curtail all "through and out" transactions, and only then as necessary curtail *pro rata* (at the wholesale transmission level) the transactions of all LSEs sinking loads in the ITP's footprint and paying the ITP's fixed transmission costs. The LSEs' own corresponding service curtailments at the distribution/end user level should be done in accordance with relevant state and local policies, as discussed above.

The VSCC is disturbed by the Commission's proposal to require the ITP, if it must curtail scheduled deliveries, to curtail first "Parties who do not have Congestion Revenue Rights in adequate amounts for their Receipt Point-Delivery Point combinations." SMD Tariff, Part II.B., Section 9.3 (Appendix B, Page No. 60,

[21] See Federal Power Act § 201(b), 16 U.S.C. § 824(b) (1994) (provisions of the FPA will not apply to retail sales, and the Commission has no jurisdiction over "facilities used in local distribution").

"Curtailment of Scheduled Deliveries"), SMD NOPR at 55546. The VSCC acknowledges that the assignment of a physical attribute to CRRs, when combined with measures assuring that network customers serving load in the transmission provider's footprint have preferred access to needed CRRs, would help to address our concerns regarding the ongoing adequacy of service to native loads. We do not, however, believe that CRRs should have any physical attributes; rather, they should be purely financial instruments. This is especially so if CRRs are to be auctioned to the highest bidder. Giving CRRs such a scheduling priority will invest them with additional inherent value over and above their ability to provide congestion revenues to the holder. This will create an economically perverse incentive for those with the motivation and financial resources to speculate in CRRs to "corner" the market for a vital public service. LSEs who are thus unable to obtain the CRR combinations that they need through such auctions will be unable to avoid dealing with such speculators, and paying premium prices for the CRRs so amassed.[22] The VSCC therefore opposes giving CRRs such a physical attribute.

Rather than giving transmission customers holding CRRs such a curtailment priority, as noted above, the VSCC supports giving priority to the transmission schedules of those LSEs serving load in the ITP's footprint and paying their allocated share of the ITP's fixed transmission costs. These LSEs (and through them, the end users they serve) are paying for the fixed costs of the ITP's transmission system. Payment of these costs should confer some associated benefit on them, or these customers would effectively subsidize the service of other system transmission customers. It is therefore appropriate to provide a curtailment preference to entities serving end users on the ITP's system that are through their rates defraying the ITP's fixed transmission system costs.

[22] Cf., "Congestion Revenue Rights: Implications for State Public Utility Commissions," Robert J. Graniere, National Regulatory Research Institute Paper No. 02-14, October 2002, at 32-34 (discussion of potential speculation in CRRs by "financial intermediators").

D. Transmission Pricing

1. Rates for Bundled Retail Customers

Notwithstanding the foregoing discussion of the Commission's proposal to place retail customers under the interim tariff, should the FERC persist in asserting jurisdiction over bundled retail customers, by requiring that service to these customers be taken under the interim tariff, it should refrain from attempting to assert jurisdiction over the transmission component of bundled retail rates. SMD NOPR at 55477, para. 178. Such intrusion into what has long been a state matter would have major and unduly burdensome implications. State Commissions would be forced to conduct detailed unbundling rate proceedings for each of their respective electric utilities to reestablish the distribution and generation components of retail rates in order for this proposed remedy to be meaningful.

Given the tremendous costs associated with such proceedings, many states might simply respond by accepting the FERC rate as is, and declaring that the residual between the FERC rate and the previously approved retail rate represents the generation and distribution component of retail rates. States (such as Virginia) with existing legislated rate caps might be required to readjust these legislated rates in such a fashion. If states respond in this fashion, the total rate would continue to be the same.

2. Transmission Pricing: Inter-Regional Transfers

If Transmission System Fixed Costs Are Removed From "Through-and-Out" Rates, Transmission Customers Paying Such Costs Should Receive A Higher Priority of Transmission Service.

The Commission in its SMD NOPR proposes to eliminate the payment of ITP access charges by transmission customers conducting "through-and-out" transactions. SMD NOPR at 55466, para. 180. At the same time, all Network Access Service ("NAS") customers, whether they serve loads on the ITP's system or conduct through-and-out transactions, are (at least in theory) entitled to equal access to all of the ITP's receipt and delivery points. Id. at 55472, para. 141. The Commission notes that under this system, "[w]e would expect that in most instances, it would be a load-serving entity, rather than a generator or a marketer, that would be the customer for transactions that result in power leaving the grid, and thus, the load-serving entity would be the entity paying the access charge." Id. at 55472, para. 142.[23] The VSCC believes that this proposed approach is inequitable. It is fundamentally unfair to expect a customer to bear the ITP's embedded transmission system fixed costs, either through the Commission-approved transmission access charges or bundled retail rates, without having any higher priority in using these transmission facilities than those who do not bear such fiscal responsibility. Conceivably, an LSE customer could be put in the position of contributing to the embedded cost of a transmission facility without being allowed use of that facility, if it is outbid in the acquisition of the needed CRRs, and it cannot pay the necessary congestion costs.

The VSCC believes that those ITP transmission customers that serve loads within the ITP's footprint and that pay their allocated share of the ITP's transmission fixed costs should be entitled to certain corresponding rights: (1) priority allocation of the CRRs needed to hedge transmission service to their loads, outside of any CRR auction process; and (2) a physical curtailment priority if the ITP cannot honor all transmission schedules after the application of its LMP-based congestion management scheme.

[23] The Commission explains that "[a]n end-use customer in a state with retail access could be the entity taking transmission service and paying the access charge." SMD NOPR at 55472, n.88. The VSCC agrees that this might occur in the case of an extremely large end use customer, with the necessary resources to participate directly in wholesale markets, but an overwhelming majority of retail customers will take service through the intermediary of an LSE. In such event, the retail end user should be able to change LSEs without any negative impact on its new LSE's ability to obtain the increased CRRs needed to hedge the associated transmission service. In other words, the VSCC agrees with the Commission that CRRs should "follow the load" and be reallocated to new LSEs, as shifting retail loads require. Id. at 55477, para. 173. See also Occidental Chemical Co. v. PJM Interconnection, L.L.C., et al., 101 FERC ¶ 61,005 (2002).

E. <u>The New Congestion Management System</u>

1. Locational Marginal Pricing

Immediate Implementation of LMP Without Adequate Mitigation Could Lead to Substantial Cost Increases and Permit the Exercise of Generation Market Power.

The VSCC recognizes that the Commission finds the idea of mandating the use of LMP as a mechanism for pricing transmission congestion nation wide very appealing. In theory, LMP would provide improved economic signals for locating new generation or transmission facilities and promote more effective load management. The VSCC, for its part, is familiar with PJM's implementation of LMP. Retail electric customers on Virginia's Eastern Shore are served by both Conectiv and rural electric cooperatives that take transmission service from PJM. In addition, Allegheny Energy provides service to retail electric customers in Virginia through its subsidiary, The Potomac Edison Company. Allegheny Energy is a transmission customer of PJM West. The VSCC, in its capacity as a member of the Mid-Atlantic Conference of Regulatory Utilities Commissioners ("MACRUC"), has worked with PJM in the past to attempt to address concerns with PJM's transmission and market operations. This experience leads the VSCC to believe that the Commission's proposed "flash cut" application of LMP in regions where it has not yet been instituted poses a number of problems.

First, LMP can, and in the VSCC's view should, be seen as a mechanism that requires control of *generation*. Section 201(b)(1) of the Federal Power Act states the FERC "shall have jurisdiction over all facilities for such transmission or sale of electric energy, but *shall not have jurisdiction over facilities used for the generation of electric energy* or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter." Federal Power Act § 201(b), 16 U.S.C. § 824(b)

(1994) (Emphasis supplied.)[24] Thus, the Commission does not have the authority to dictate to any regulated "public utility" that it must generate power and sell it to an ITP to facilitate a market that produces LMPs. Yet, the Participating Generator Agreement ("PGA") that is proposed in the SMD Tariff (Part IV, Section 1.1) would *require* "all available capacity" of a generator to be either scheduled or offered to the ITP's Day-Ahead or Real-Time markets. SMD NOPR at 55569. On its face, this provision asserts jurisdiction by the Commission over generation facilities, which it simply does not possess. Moreover, while this Commission may believe that New York v. FERC authorizes the extension of its jurisdiction to the retail transmission component of bundled rates as asserted in the SMD NOPR, nothing in this U.S. Supreme Court opinion signals a shift in jurisdiction over generation pricing, reliability and adequacy from the states to this Commission—directly, or indirectly through ITPs.

This jurisdictional issue must be resolved if the Commission is to implement LMP. If operational control over generation facilities is, as the VSCC believes, necessary to implement LMP in the manner envisioned by the Commission, then FERC needs Congress to amend the FPA to give it that authority.

Second, the use of LMP can, and has been shown in certain instances to, dramatically increase power supply costs for municipalities, cooperatives, and other LSEs, such as a distribution utility that has "spun-off" or otherwise divested its generation assets during a transition to retail access. An LSE must either own or have contractual rights to sufficient power supplies from generation units located behind a transmission constraint if it is to fully hedge against congestion costs incurred to serve

[24] See, e.g., Citizen Power, Inc. v. FERC, D.C. Cir. No. 01-1240, 202 U.S. App. Lexis 11847, (unpublished opinion), *rehearing denied*, 2002 U.S. App. Lexis 13219, *cert. denied*, 2002 U.S. Lexis 8711 (December 2, 2002) (Court affirmed FERC ruling that it has no jurisdiction under FPA Section 203 over disposition of generation facilities by public utilities, because of the jurisdictional limits placed on FERC by FPA Section 201(b)).

loads in such "pockets."[25] In its drive for what it believes to be greater economic efficiency, the Commission seems to wish this problem away by assuming that LSEs will enter into bilateral power supply contracts with generators in such load pockets sufficient (in conjunction with their CRRs) to hedge their transmission congestion costs effectively. But, the owners of generation units behind such transmission constraints may or may not in fact be willing to enter into bilateral agreements with such LSEs.[26] Any such contracts, however, would undoubtedly recognize the seller's expectations of financial gains under LMP and the respective and unequal bargaining positions of the parties. Thus, even a generation owner of a unit with low production costs will seek a higher contract price, if the owner expects that other, higher-cost units will set the LMP during a significant number of hours.

This scenario points out a fundamental flaw in the Commission's reasoning supporting its proposed implementation of SMD. In paragraph 11 of the NOPR, the Commission acknowledges that SMD might "raise concerns that cheap power may leave one region for sale in another, higher-priced region." The Commission's answer to this dilemma is that "customers in low-cost regions can ensure that low-cost power 'stays home' by contracting for that power." Id. This is no answer at all. If the selling generator knows that it can obtain a higher price by "exporting" its power to another region, then it is going to demand a comparable premium (less only any transmission-related costs it

[25] This is so because, by definition, there will be insufficient CRRs to hedge all loads behind the transmission constraint, due to the operation of the simultaneous feasibility requirement. See Statement of Andrew Ott, Executive Director, Market Development of the PJM Interconnection at the Commission's December 3, 2002 CRR Technical Conference held in this docket ("I think, in and of itself, a load pocket, I guess there's an area where you don't have enough transmission capability to serve load into that area, so I think that, in and of itself, the CRR allocation auction or whatever cannot solve the load pocket problem."). Transcript at 69.

[26] While a generation owner in a pocket may contract for financial certainty reasons, if it serves load in that pocket in competition with another LSE, it may be unwilling to sell power to that LSE, simply for competitive reasons. The Commission must take such basic considerations into account in implementing SMD.

would avoid paying) to keep that power "at home." The end result is still a hefty increase in the cost of power to buyers in formerly low-cost regions. Thus, the Commission's advice to those in low-cost states to "just buy the power yourself" has a ring reminiscent of "let them eat cake."

Third, the transition to LMP can have surprising results. In most areas where traditional utility cost-of-service regulation has been used up until now to develop retail electric rates, generation costs are averaged. Thus, the higher cost of running "out-of-merit" generation units is not transparent to end use customers. Moreover, traditional regulated utilities constructed transmission and generation facilities interchangeably to serve their loads at the lowest overall cost, and the retail rates for both generation and transmission were cost (not market) based. While this system provided service to all customers at a regulated cost-of-service rate, it also served to socialize the effect of transmission constraints on generation pricing over a broader region. This approach, while not necessarily desirable from an economic efficiency perspective, served a number of legitimate objectives. A changeover to LMP, with its market-based spot power prices (which are in turn used to price transmission congestion), turns a bright spotlight on all of these economic trade-offs. Moreover, as new regional power trading patterns emerge and develop, transmission paths that previously were not constrained can become so.

Consequently, LSEs providing service in areas changing over to an LMP regime may have little knowledge of where to expect higher marginal prices. This can be particularly true for new entrants into recently unbundled retail markets. Given the complex, dynamic nature of the grid, it could be very difficult to predict where and when transmission constraints will occur. As a result, many LSEs, particularly those that have less exposure to the day-to-day operation of the grid (e.g., municipalities, cooperatives, new entrants into retail markets, etc.), may not have the expertise or knowledge to develop an appropriate resource mix and to acquire the right portfolio of CRRs (even assuming sufficient CRRs are in fact available). LMP and its associated risks could therefore be a substantial barrier to entry in states like Virginia that are seeking to develop a competitive retail market. A well-designed transition to LMP is needed to protect against such rate shocks and to allow parties with limited or no experience to successfully navigate the shoals and reefs of an LMP-based congestion management system.[27]

Such a transition to LMP should include affirmative steps to ameliorate the cost increases that customers in transmission-constrained areas would otherwise experience as the result of the "unbundling" of generation and transmission costs, and the move to generation market-based pricing of transmission congestion costs. It is not acceptable as either a legal or policy matter to implement an LMP-based SMD, but then disclaim responsibility for the attendant cost increases visited on retail electric customers in load pockets. The Commission, however, appears to be flirting with just such a course in New England Power Pool, et al., 2002 F.E.R.C. Lexis 2627, 2650 (December 20, 2002) at n.13 ("NEPOOL"). The Commission there agrees with a protesting party that "proper price signals alone will not attract new generation and transmission capacity" into a load pocket located in Connecticut, but it nonetheless permits the "localization" of reliability must-run ("RMR") costs incurred to serve that area (i.e., the charging of such RMR costs solely to retail customers in the load pocket). The Commission's rationalization for allowing this result is that the "other obstacles to the development of new resources are simply beyond the jurisdiction of the Commission." But this is no response at all. The Commission is the regulatory entity approving the rate design and market changes leading to the increased charges to retail customers in this load pocket. It therefore must

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[27] The VSCC is currently attempting to evaluate the potential effects of a change to LMP pricing on retail electric customers on the Virginia mainland if Virginia Electric & Power Company ("VEPCO") and Appalachian Power Company ("APCO," a member of the American Electric Power holding company system) join the PJM ISO, as they have proposed to do. To date, the VSCC has been unable to obtain hard data assuring that additional retail electric customers in Virginia will not be exposed to substantial cost increases as a result of such a change similar to what has been experienced in other areas of the state.

take responsibility for ensuring these customers can somehow respond to the price signals that are "sent" to them.

The VSCC notes that the Commission in NEPOOL attempts to moderate the financial impact of LMP on these customers, by encouraging the building of "a defined set of transmission upgrades into Southwest Connecticut, identified at the start of the implementation of LMP," and the assignment of "a portion of the upgrade costs to other New England customers."[28] A better alternative, however, would be to follow the advice of the Department of Energy in its comments filed in this docket on December 20, 2002 (at 6): "[i]deally, given the lead-time required to put such [transmission capacity or a suitable substitute] in place, additional investments should be planned and built before LMP begins to flash its price signals in real time."

Fourth, LMP may not in actual operation provide the right economic incentives to customers when all factors, both price and non-price, are considered. LMP may provide greater incentives to develop generation or transmission facilities in a given location, without adequately recognizing other legitimate societal interests (including protection of environmentally sensitive areas and historic resources, and the need to avoid further burdening residents and businesses in already economically depressed areas of a state).

Perverse economic incentives resulting from the use of LMP may also serve to increase opposition to the construction of needed utility infrastructure. For example, the owners of generating facilities that derive greater profits through an LMP-based regime may seek to obstruct the construction of any facility (e.g., a new transmission line) that would relieve congestion and thus reduce their profits. This problem is heightened when the entity accruing the increased generation profits is also the incumbent transmission owner in the area, and thus the only entity with the legal authority under state law to build a new transmission line.

[28] Id. at 36.

Practical realities may also prevent LMP from fulfilling its promise of optimizing load management alternates because price signals are not passed directly on to end users. Given the volatile nature of LMP and the limits of the current electric distribution infrastructure and billing systems, it is unlikely that an LSE would be able to pass these signals on directly to every end user. Even if this could be done, exposing residential and small commercial end users to the high volatility inherent in LMP is only appropriate if these users can somehow respond to those signals. If they cannot do so, then such pricing takes on a punitive element that is both undesirable from a societal and political standpoint and intolerable from a political standpoint.

Fifth, and finally, the Commission must recognize that an LMP-based congestion management regime can, if not properly implemented, unintentionally serve as a vehicle for price manipulation and market power abuse. The theory undergirding LMP presupposes that power suppliers will bid into the ITP's power markets at their respective marginal costs of production, and receive a single market-clearing price based on such marginal cost bids. SMD NOPR at 55479, para. 204, n.16. In fact, suppliers may submit bids based on many different factors, including their knowledge that the ITP will in fact have to accept their bids (regardless of the price offered) because their generation units are required to operate the system, or that bids of other suppliers made at a certain level (e.g., cost-mitigated bids of must-run units) will have to be accepted, hence setting an effective "floor" price for all other bids.

Consequently, effective market monitoring and timely market power mitigation are absolute necessities if an LMP-based congestion mechanism is to be implemented. Monitoring must be both consistent and sophisticated, because certain abuses may be extremely difficult to identify and correct. For example, the owner/operator of multiple generating units behind a transmission constraint can benefit significantly if the market-clearing price is driven upward by a forced outage at a single unit. As has been evident in the Commission's investigation of the California wholesale market, it is very difficult for an outside observer to ascertain whether an outage truly is forced, or has been fabricated or extended for economic reasons.[29] Market monitors must therefore be independent (and hence not subject to "censoring" by ITP managements or market participants), and possess sufficient expertise and resources to do their jobs. They must also have sufficient authority to require market participants whom they suspect of engaging in abusive market conduct to "cease and desist" from such practices, pending expedited review by the proper adjudicative body of the questioned conduct. Without vigilant market monitoring and effective mitigation, much damage can be inflicted on end use customers with little or no ability to protect themselves. The VSCC comments more extensively on market monitoring and mitigation in a later section of these comments, but raises these topics here to make crystal clear the essential tie between implementation of LMP-based congestion management and effective market monitoring and mitigation.

Because of these numerous concerns, the VSCC believes that LMP should not be adopted on a wholesale basis in all regions of the country. Instead, LMP should be implemented on a case-by-case, region-by-region basis only, and following careful consideration of the effects that LMP will have in a given area *and* with the concurrence of impacted state commissions. If analysis shows that a region's transmission and generation infrastructure is insufficient to support a move to LMP without substantial cost increases, or that the exercise of generation market power could adversely impact

[29] See "Non-Public Appendix to Order Directing Williams Energy Marketing & Trading Company and AES Southland, Inc. to Show Cause," FERC Docket No. IN01-3-000, publicly released on the Commission's website on November 14, 2002, at 3 (Narrative report discussing, *inter alia*, transcripts of taped telephone conversations between AES and Williams employees regarding outages at AES' Alamitos No. 4 generation plant in California, in which a Williams representative is quoted as having told an AES employee "it wouldn't hurt Williams' feelings if the outage ran long," and in a conversation with another AES employee as having said "I don't wanna do something underhanded, but if there's work you can continue to do...," only to be interrupted by the AES employee as follows: "I understand. You don't have to talk anymore.").

power supply markets in the ITP's region, then movement to LMP should not occur until these problems are addressed and resolved.

2. Congestion Revenue Rights

Retail End Use Customers of LSEs Paying the ITP's Transmission System Fixed Costs Should Be Allocated CRRs on an Ongoing Basis.

The VSCC believes that the Commission needs to consider very carefully the issue of CRR distribution. It should not adopt a "one size fits all" approach to CRR distribution and revenue allocation. As noted earlier, an LSE (especially one serving retail customers in an open access state) might find it extremely difficult, at least initially, to determine the "right" set of CRRs that it will require, due to lack of intimate knowledge of transmission system operations and unanticipated changes in system flows. This is particularly true given that the CRRs available to date have been obligations, under which dollars must be *paid out* in the form of "negative congestion revenues" if congestion "reverses." Thus, a CRR obligation that an LSE obtained with the intent of holding it as a hedge against the payment of congestion costs could result in a requirement to pay out congestion revenues to the ITP. SMD NOPR at 55485, para. 245.[30]

Moreover, the Commission, as noted above, is proposing to require ITPs to limit the aggregate amount of CRRs available to those "simultaneously feasible based on Available Transfer Capability under normal operating conditions." Id. at 55486, para. 250. The complexity of this "simultaneous feasibility" criterion, coupled with the fact that it is based on a "snapshot" in time of "normal operating conditions" (obviously a judgment call on the part of the ITP, since there is no one set of such conditions), makes it very difficult for LSEs to ascertain the optimal set of CRRs to hedge their loads. This

[30] In theory, the payment of such costs would be offset by lower power costs available to the payor from the ITP's spot market. If, however, the LSE holding the CRR is locked into a longer-term bilateral agreement or is self-scheduling its own power from its own units, it may not be able to take advantage of such lower costs.

is particularly true if an LMP-based regime is being introduced for the first time. The VSCC is also concerned that CRRs could be used by market participants in conjunction with their other owned or controlled resources, such as generating units, to create greater opportunities for market manipulation. For example, an LSE may have a greater ability to increase its revenues through market manipulation if it has both CRRs and substantial generating unit ownership interests, especially if those units are located in transmission load pockets.[31]

As discussed above in Section C., the VSCC believes that CRRs should be purely financial instruments, with no attendant scheduling/curtailment priorities. If CRRs carried such a priority, the obligation to serve that is placed on LSEs would put them in even greater need of CRRs, in that CRRs would be needed for reliability assurances as well as financial protection. This would reduce liquidity of any resale market in such rights, and increase opportunities for entities without the appropriate mix of CRRs to be held hostage to market manipulation.

The VSCC strongly advocates annual allocations (as opposed to auctions) of CRRs to LSEs serving load in the ITP's region and paying the fixed costs of the ITP's transmission system. Such a regime is more likely to allow LSEs to employ firm, but flexible, transmission service and the associated congestion hedging rights to obtain access to a broad universe of generators. LSEs that are not incumbent transmission owners (especially new entrants concentrating on the provision of retail open access power supply) simply do not have the same resources to devote to a CRR auction process, running the innumerable CRR scenarios and developing the complicated bidding strategies, as do larger, more established auction participants. The cost of obtaining such

[31] This issue is discussed in some detail in the "Affidavit of Frank A. Wolak" attached to the "Joint Comments on Market Power Mitigation Issues of the Electricity Consumers Resource Council, the Transmission Dependent Utility Systems, Great River Energy, Buckeye Power, Inc., Wolverine Power Supply Cooperative, Inc. and the East Texas Cooperatives," filed on November 15, 2002, in this docket regarding local market power mitigation and market monitoring.

resources would be significant. It makes much more sense from such an LSE's perspective to have the ITP simply evaluate an LSE's designated load and resources and allocate CRRs to it accordingly. The LSE might bid for CRRs in an auction according to its best guess of the CRR portfolio that it needs, and yet still end up with a set of CRRs that does not in fact cover the congestion costs associated with its transmission service.

Keeping CRRs in the hands of LSEs through an allocation process would also require generators to compete with one another to serve LSEs, *based solely on the price and terms of their generation service*. In contrast, institution of an auction process for the initial annual allocation of CRRs could open the door to speculation by generators, marketers, financial institutions and non-industry participants in such rights. The ability of LSEs serving load in the ITP's footprint and paying the ITP's fixed transmission system costs to obtain reliable transmission service and hedge transmission congestion costs should not be undermined by financial speculation in the needed CRRs, particularly speculation by entities that have no service obligations to customers. Please note that while the VSCC advocates an allocation process for assigning CRRs to load serving entities, we believe that any such process must also accommodate the development of retail competition by assuring that CRRs follow load as new entrants gain market shares.

Those market participants supporting a full auction regime for CRRs have argued that LSEs paying transmission system fixed charges would be "kept whole" through their receipt of revenues from the CRR auctions. Even some on the Commission's Staff have taken this position, going so far as to assure LSE representatives that LSEs can "bid infinity" in any CRR auction to ensure they obtain the CRRs they need, secure in the knowledge that they will receive sufficient auction revenues to pay off their bids. LSEs executing such an auction strategy, however, could easily be accused of attempting to "game" the auction, thus thwarting its intent. Moreover, if LSEs, a substantial portion of the likely universe of CRR bidders, must "bid infinity" to ensure the receipt of sufficient CRRs to serve their loads, this would certainly undermine the viability and results of any such CRR auction. It would be preferable from a transparency standpoint to have a straightforward CRR allocation (with a supplemental auction for excess and short-term CRRs), rather than a full CRR auction with such a dubious starting premise.

Nothing in the SMD NOPR guarantees LSEs that the dollar allocation of CRR auction revenues they receive would in fact offset the amount of their CRR bids and/or their actual congestion costs and thus keep them and their retail customers whole. Indeed it is unclear just how the CRR auction revenues would be allocated under SMD. One allocation measure that has been mentioned is the use of LSEs' load ratio shares of transmission system usage (which is also how the Access Charge would be allocated). If the load ratio share method of allocating auction revenues is used, then an LSE's allocated share of the auction revenues undoubtedly would *not* match that LSE's actual congestion costs. Any LSE paying Access Charges would receive auction revenues under such a load ratio share allocation, whether or not it even sought to purchase CRRs in the auction. The irony of LSEs obtaining insufficient auction revenues to cover their CRR bids and/or congestion costs is of especially great concern to the VSCC, because Virginia retail customers as a result could find themselves paying retail rates that include substantial uncompensated costs paid to purchase CRRs and/or unhedged congestion costs, simply to maintain access to transmission facilities that they have already paid to depreciate over many years.

The Commission proposes that the revenue deficit or surplus remaining after the hourly CRR settlement process would be allocated to the ITP's transmission owners. SMD NOPR at 55486, para. 251; Appendix B, SMD Tariff, Part III. F., Section 3.6.3, Page No. 103. Id. at 55556-7. The Commission posits that such revenue deficits should be made up by the transmission owners whose transmission facilities are out of service (excluding force majeure events). This "would encourage transmission owners to take steps to minimize forced transmission outages and to schedule maintenance outages so as to minimize their effect on congestion costs." Id. at 55486, para. 251. The VSCC agrees that if transmission owners were required to absorb these revenue deficits, they would have a very real financial incentive to minimize such outages—an incentive that is not now always present.

The Commission further proposes to pay CRR revenue surpluses to transmission owners. However, the Commission acknowledges that this policy "may also create an interest on the part of transmission owners in maintaining congestion, and thus may discourage them from building needed transmission expansions." Id. The Commission therefore seeks comment on whether such excess dollars should be paid to transmission owners, or whether such an allocation would discourage transmission expansions. Id.

The VSCC shares the Commission's concern that allowing transmission owners to receive surplus CRR revenues could discourage transmission expansions and conversely encourage continued congestion. Hence, the VSCC would support allocating such surplus CRR revenues to those entities holding CRRs. If CRRs are allocated to ITP transmission customers serving load in the ITP's footprint and paying the ITP's fixed transmission system costs, this revenue allocation could then be passed through by these LSEs to retail end users taking service in the ITP's service territory.

F. Day-Ahead and Real-Time Market Services

The Commission Should Not Require ITPs to Implement in a "Flash Cut" a Full Array of Energy and Ancillary Services Markets, But Should Allow ITPs to "Start with the Basics."

Detailed critiques of the portions of the SMD NOPR and the proposed SMD Tariff dealing with the operational aspects of the Day-Ahead ("DA") and Real-Time ("RT") markets will, the VSCC believes, be presented in comments by such market operators. The VSCC has a number of general concerns, which it urges the Commission to consider as it assesses the essential features of these markets.

First, the Commission appears to have constructed what it regards as a "best practices" tariff for DA/RT market services, taking provisions from a number of different ISO tariffs and operating procedures. The Commission, however, must be careful not to unintentionally construct a "Frankenstein" DA/RT market in the process. By mandating that ITPs offer an entire array of DA and RT ancillary services, the Commission has exponentially increased the complexity of the task that lies before ITPs, especially "greenfield" ITPs that will be forming in regions of the country with no existing tight power pools. It will be difficult enough to achieve workably competitive or adequately mitigated DA/RT energy markets in many parts of the country. Because in many cases, a limited number of suppliers will be able to provide certain ancillary services, these markets will consequently be even "thinner" than the companion energy markets. This likelihood alone should raise a large red flag for the Commission.

The ITP's running of the bid-based, security constrained Unit Commitment ("UC") is the starting point for each day's market operations under the Commission's proposed market regime, and is thus critical to its success. The chosen units from the UC are run through the ITP's security-constrained dispatch and pricing program to develop locational prices on an hourly basis. The market mitigation rules used to mitigate the bids of "reliability must run" units or units that otherwise enjoy generation market power are thus of the utmost importance. If these rules are not sufficiently rigorous, then the resulting rates will not be just and reasonable. Close cooperation among the ITP's markets and operations Staff, the Market Monitor, and the Commission will be necessary to ensure that rates are just and reasonable.

ITPs (especially those not yet in operation as RTOs/ISOs) will likely have to climb a steep learning curve at the commencement of operations in running such a UC process simultaneously for all markets, including the individual proposed ancillary services markets. The Commission may therefore wish to allow ITPs to start with

DA/RT energy/imbalance markets, and only institute markets for other ancillary services at such time that these additional markets and operations become desirable and feasible.

The VSCC is also concerned that certain proposed provisions of Part III of the SMD Tariff seem to be more concerned with maximizing the revenues of those entities selling into the ITP's markets than in ensuring just and reasonable rates. For example, in the Preamble set out in Part III.F. of the proposed SMD Tariff (Page No. 81), the ITP is required to develop the Day-Ahead Schedule to "maximize the combined economic value of Transmission Service, Energy, and Ancillary Services, based on the Bids submitted." SMD NOPR at 55551. In the VSCC's view, the ITP should be developing day-ahead schedules to provide all requested services at the *overall least cost to transmission and market customers.* This obligation imposed on the Commission by the FPA is very likely inconsistent with "maximizing the combined economic value of all services," and if it is, this section should be revised to conform to the Commission's enabling authority.

In a similar vein, the charge of the ITP as set out in Part III.F., Section 1.5 of the proposed SMD Tariff (Page No. 83) is to develop a UC computer algorithm that "maximizes the total value of the Bids" submitted during the day-ahead bidding process. Id. at 55552. The Commission should clarify that the primary objective of the UC function is to *minimize* the total costs of transmission, energy, and ancillary services to LSEs and the end users they serve.

Moreover, the tariff provisions setting out the method of calculating the market-clearing prices for a number of different ancillary services have been complicated by the introduction of a "most favored ancillary service" policy into the SMD Tariff."[32] Such a policy can transfer market dysfunctions from one market to another, which can be

[32] For example, under Part III.F., Section 4.5 (Page No. 108), if the market-clearing price for Operating Reserves is higher than the price for Regulation, then the generator obtains that higher price for supplying Regulation. SMD NOPR at 55558. Other tariff sections dealing with the pricing of other ancillary services contain similar "higher of" pricing provisions.

financially detrimental to end use customers. The VSCC questions the wisdom of giving generators a market price higher than the market price for the service that they themselves chose to bid on and for which their specific generation was selected to provide.

The VSCC also is concerned by certain of the provisions of Part III of the SMD Tariff dealing with the treatment of demand response bids. Demand bids should undoubtedly be an important component of the DA energy market. But the "optional bid components" identified in Part III.F., Section 2.3.1 (Page Nos. 87-89) attempt to allow demand response to act as the equivalent as a generating resource in the event that curtailment may be needed to balance supply and demand during tight periods. SMD NOPR at 55553. Demand and generation resources, however, cannot be treated as if they were interchangeable, because they are not capable of providing the same services. Demand responsive loads generally have limited ability (in terms of time) to control or reduce their demands. In addition, unless significant protections are built into the selection of these resources in the Day-Ahead market, there is tremendous potential for gaming. Since almost all "actual loads" are now served at retail, it is difficult for an ITP operating wholesale markets to interact directly with retail loads participating in those markets, and to verify their actual performance.

Acceptance of Demand Bids also raises questions of equity. If an end user reducing its demand saves the cost of purchasing energy in a high-cost hour, that savings alone can be very substantial. End use customers reducing their demand should not receive more in aggregate (the end user's avoided costs plus payments for incremental reductions in the market clearing price for generation) than the market-clearing price that the ITP pays to generators in that same hour. The VSCC understands that in the PJM and ISO-NE markets this past summer, end users reducing their demand in a particular hour were in some cases paid substantially more than generators producing power in that same hour. Payment of such premiums to specific end users, however, must be remitted by all other customers, and thus such payments send false economic signals to customers reducing their demand as to the value of their "service." Such uneconomic pricing should therefore not be permitted under the SMD Tariff. The ITP should also prohibit, as PJM now does, demand responsive loads from collecting payments for reducing their demands at both the wholesale and retail level.

In sum, the VSCC is concerned that certain provisions of Part III of the SMD Tariff seek to give excessive flexibility and revenues to energy and ancillary service providers, at the expense of end use customers. The VSCC questions whether such flexibility would result in just and reasonable rates. Moreover, by trying to adopt "best practices" from differing market regimes, without incorporating the associated safeguards, the proposed Tariff may create opportunities for further gaming. If the Commission goes forward with its SMD proposals it would be well advised to take the "less is more" approach to market development, requiring ITPs to implement SMD in stages, with basic DA and RT markets in the initial stage, and ancillary services markets in a later stage. Further changes should be allowed to evolve in a deliberate fashion.

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

1. Capacity Benefit Margin

Capacity Benefit Margin Practices Need to Be Reformed, But CBM Still Has a Role To Play in Assuring Reliability.

The Commission at paragraphs 330-331 of the SMD NOPR effectively proposes to eliminate CBM, and to instead require each LSE seeking access to resources on a neighboring transmission system to "acquire Congestion Revenue Rights from the interface to its load to ensure that access." SMD NOPR at 55496, paras. 330-331. While the VSCC agrees that changes in the current practices for reserving CBM are certainly needed, the VSCC thinks there is a better way than how the Commission has proposed to deal with this issue.

Past problems with CBM have arisen primarily because individual public utility transmission providers with associated merchant functions set aside CBM on the rationale that it was needed to assure reliable service to their own bundled native retail loads, deducting such capacity from their ATC at the interfaces into their systems. The arbitrary nature of these set asides, the inability of other transmission customers to use this capacity, and the possibility that certain public utilities were "dipping into" CBM to conduct profitable wholesale transactions, led to substantial dissatisfaction with the entire concept, and subsequent calls for its elimination.

If, however, a fully independent ITP takes over operation and control of the regional transmission system, then theoretically it could make a dispassionate and rational assessment of the amount of interface capacity that LSEs serving loads in the ITP's footprint will need to assure reliable service to their loads.[33] In the event that through-and-out customers do not contribute to the ITP's transmission system fixed costs through the payment of an Access Charge, it would make economic sense to make this allocation of CBM available to all LSEs that are in fact paying such Access Charges, if they need this capacity to deal with generation contingencies or other unanticipated supply disruptions.

This approach to CBM is superior to the Commission's proposal, in that it does not require each LSE to individually "firm up" its in-region resources by attempting to obtain additional CRRs which may be in short supply due to the operation of the simultaneous feasibility criterion. SMD NOPR at 55496, para. 331. A collective CBM "reliability insurance policy" held by the ITP for the benefit of all LSEs serving load on

[33] The ITP should have a good idea of the mix of in-region and out-of-region resources that each LSE will be using to serve its loads, due to each LSE's obligation to meet the Resource Adequacy Requirement, discussed further in other sections of these comments.

its system and paying Access Charges would require fewer system resources than individual LSE CRR holdings (the equivalent of a series of individual reliability insurance policies). Moreover, the ITP can make CBM available on a recallable basis to market participants when it is not needed for reliability purposes. Because the ITP is an independent system operator, with no interest in withholding system capacity, the suspicion that CBM is being or could be withheld for anticompetitive purposes should no longer be an issue.

The SMD NOPR's proposed elimination of CBM could potentially create additional generation-related costs for LSEs in the ITP's own footprint, while not reducing their transmission-related costs. The Commission should retain CBM, but make it "transparent" and available for use by all LSEs serving load in the ITP's region and paying Access Charges.

2. Regional Planning Process

The NOPR provides that transmission planning and expansion will seek to meet the needs of a regional planning area. The NOPR proposes that states' role in the approval and siting of new transmission facilities could be through states' participation in Multi-State Entities ("MSEs"). All public utilities owning transmission must participate in a planning area from the outset with the ITPs becoming progressively part of the process. The NOPR suggests that planning areas could be made up of multiple existing ISOs or RTOs; thus, planning areas are intended to include multiple regional markets.

While the VSCC agrees that adequate transmission infrastructure is needed to support reliable, regional wholesale markets, the VSCC is concerned that the approach taken by the NOPR ignores current regional market planning, as well as state responsibilities over approval and siting of transmission facilities. The need for MSEs has not been adequately shown. The NOPR does not demonstrate why the proposed regional planning areas, which, as proposed, may span large geographic areas and consist of multiple regional markets, will be the best means to meet the needed transmission infrastructure goals. The NOPR effectively proposes to include Virginia in two regions (one based on RTO configuration and one based on reliability council membership) even though under current utility plans Virginia would have transmission control transferred to only one region. Currently, Virginia utilities plan to join either PJM or MISO. Virginia's largest electric utility, Virginia Power, is, however, a member of SERC. This juxtaposition of RTO and reliability council was made without any explanation and seems to have been made with little detailed consideration. Without a clear demonstration and understanding of how this proposal would more adequately meet transmission planning goals, Virginia should not be expected to commit time and resources to become part of a planning process that involves two overlapping regions.

In addition, states' limited roles as participants in these MSEs might unduly limit existing state authority over approval and siting of new transmission facilities within states' borders. Approval and siting of transmission facilities has been reserved to the states. States have statutory obligations over approval and siting of transmission facilities within their borders. For example, the VSCC has authority over the construction of transmission in the Commonwealth pursuant to Va. Code § 56-265.2.[34] Virginia statutes also require the VSCC to consider environmental, historic and scenic impacts when permitting the construction of such facilities pursuant to Va. Code § 56-46.1.[35] Virginia's

[34] Virginia Code § 56-265.2 states "[i]t shall be unlawful for any public utility to construct, enlarge or acquire, by lease or otherwise, any facilities for use in public utility service, except ordinary extensions or improvements in the usual course of business, without having obtained a certificate from the Commission that the public convenience and necessity require the exercise of such right or privilege."

[35] Virginia Code § 56-265.2 cross references Virginia Code § 46.1 stating "The certificate of overhead electrical transmission lines of 150 kilovolts or more shall be issued by the Commission only after compliance with the provisions of § 56-46.1." Virginia Code § 56-46.1 states "[w]henever the Commission is required to approve the construction of any electrical utility facility, it shall give consideration to the effect of that facility on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact."

Restructuring Act also specifically provides for VSCC authority over the control, operation and maintenance of transmission facilities. See, Va. Code § 56-580 A and B.[36] Additionally, the Restructuring Act authorizes the VSCC to require the expansion of transmission facilities if such facilities are needed to eliminate market power abuses or to further the development of retail competition. Va. Code §§ 56-578 F .[37] The NOPR appears to encroach upon states' key state responsibilities over the construction of new transmission facilities.

Based on the foregoing, the VSCC recommends that the Commission not require the institution of the proposed regional planning process, including the MSEs, without further exploring the need for such entities and more clearly delineating the structure, authority, and responsibility of such entities.

3. <u>The Specific Transmission Facilities That Must be Under the Control of an Independent Transmission Provider Should Be Left for Regional Determination.</u>

The Commission seeks comment in the SMD NOPR on the test that the Commission should use to determine which facilities are placed under the control of an

[36] Virginia Code § 56-580 A states "[t]he Commission shall continue to regulate pursuant to this title the distribution of retail electric energy to retail customers in the Commonwealth and, to the extent not prohibited by federal law, the transmission of electric energy. Virginia Code § 56-580 B states [t]he Commission shall continue to regulate, to the extent not prohibited by federal law, the reliability, quality and maintenance by transmitters and distributors of their transmission and retail distribution systems."

[37] Virginia Code § 56-578 F states "[i]f the Commission determines that increases in the capacity of the transmission systems in the Commonwealth, or modifications in how such systems are planned, operated, maintained, used, financed or priced, will promote the efficient development of competition in the sale of electric energy, the Commission may, to the extent not preempted by federal law, require one or more persons having ownership or control of, or responsibility to operate, all or part of such transmission systems to: 1. Expand the capacity of transmission systems:" or 2. File applications and tariffs with the Federal Energy Regulatory Commission (FERC) which (i) make transmission systems capacity available to retail sellers or buyers of electric energy under terms and conditions described by the Commission and (ii) require owners of generation capacity located in the Commonwealth to bear an appropriate share of the cost of transmission facilities, to the extent such cost is attributable to such generation capacity; 3. Enter into a contract with, or provide information to, a regional transmission entity; or 4. Take such other actions as the Commission determines to be necessary to carry out the purposes of this chapter."

ITP, whether regional variations should be permitted, and how the transmission facilities that are not placed under ITP control are to be treated with respect to open access and rates. SMD NOPR at 55500, para. 369.

The VSCC believes that the Commission should not attempt to establish a hard and fast "bright-line" test as to what facilities constitute "transmission facilities" and hence should be placed under ITP control. Instead, the Commission should provide general guidance on these issues in any Final Rule, and consult further with affected state commissions in each region when deciding which facilities should be under ITP control.

One possible approach for limiting the adverse impact of LMP-based congestion management in severely transmission-constrained areas would be to limit the extent to which lower-voltage transmission facilities are included in an ITP's LMP regime. ITPs implementing an LMP-based congestion management regime should be required to study this issue as part of any transition, to assure that the unhedged congestion costs of LSEs serving load in the ITP's footprint are minimized.

H. Transition to Single Transmission Tariff: Allocation of Congestion Revenue Rights

Allocation of CRRs Should Ensure That Existing Loads Do Not Incur Rate Increases Due to the Implementation of SMD.

As discussed previously, the VSCC strongly supports the concept that any annual allocation of CRRs (if LMP is instituted) should preserve the rights of existing transmission system customers and minimize cost shifting that might occur as a result of the move to an LMP regime. In response to the Commission's request for comment on the issue of load growth (SMD NOPR at 55501, para. 376), the VSCC states its belief that proper allowances for native load growth must be made in any initial allocation of

CRRs. LSEs providing service in an ITP's footprint could be disadvantaged if they are unable to obtain CRRs sufficient to cover their expected load growth. Given that such LSEs may have ongoing obligations to provide retail electric service, it is appropriate to reflect their expected load growth in initial CRR requests. It is even more essential that the initial allocation of CRRs include coverage of load growth if CRRs also confer a higher curtailment priority on the schedules of the entities that hold them.

The VSCC also questions the need for use of an auction in the initial allocation of CRRs. Id. at 55501-2, paras. 378-379. As noted above in Section E.2., the VSCC is concerned that the complexities introduced by LMP and CRRs could negatively impact service to end use customers in the ITP's footprint and complicate the development of competitive retail markets. An auction process simply adds another layer of complexity that could create the potential for even greater unintended adverse impacts. The VSCC therefore believes that auctions should be limited to the secondary market for CRRs. LSEs could either elect to participate in such a secondary auction or retain their CRRs, without having to try to balance auction proceeds against congestion costs.

I. Market Power Mitigation and Monitoring in Markets Operated by the Independent Transmission Provider (PP 390-456)

Without Independent and Effective Market Power Monitoring and Mitigation, SMD Will Not Result in Just and Reasonable Rates for Power Supply or Transmission Congestion.

The VSCC believes that the potential for market manipulation under an LMP-based SMD is very high. As noted throughout these comments, the VSCC believes that adoption of SMD as it is now proposed could actually increase opportunities for market abuses if steps are not taken in the Final Rule to avert such a result. Without proper market monitoring and mitigation, LMP and other aspects of the NOPR can create economic disasters similar to what occurred in California. The primary difference could be that the economic devastation would be nationwide. If such market monitoring and mitigation cannot be achieved, LMP and other provisions of the NOPR should not be adopted.

Given the breadth of products, the number of parties involved, the complexities of the markets and transactions, and the sheer volume of expected transactions, it appears that, as a practical matter, it will be impossible to have adequate monitoring and mitigation. Each time there is an opportunity for abuse, the Commission's solution is to "fix it" by saying there will be monitoring and mitigation. The ability to monitor and mitigate has not been demonstrated even on a small scale. It is ludicrous and absurd to expect such a system to spring from the ashes of California, fully formed and functioning, to police and correct the abuses of a disparate national system. Monitoring and mitigation must be tried and tested locally and expanded carefully. Even then, the task probably will be too much. At the very least the Commission should begin small and test and revise until it has a semblance of a workable system.

What is proposed is lacking, even as a place to start. The VSCC in this section therefore suggests a number of changes to the market monitoring and mitigation regime proposed in the NOPR. With these changes, the Commission may have the basis for a system that could be tested on smaller scale and expanded, with adjustments, thereafter.

Without a strong and fully independent Market Monitor ("MM"), market monitoring is doomed to fail. Some ISOs have in the past contracted with outside consulting firms to act as their MMs under terms and conditions that give undue leverage to these ISOs' managements.[38] Moreover, certain consulting firms also appear to be

[38] See, e.g., Midwest Independent Transmission System Operator, Inc., 99 FERC ¶ 61,237, at 28-30 (2002). (Commission rejected the retention agreement executed by the Midwest Independent System Operator, the Alliance Companies, and the Southwest Power Pool with a consulting firm, under which the firm was engaged as an Independent Market Monitor ("IMM"), because the scope of the IMM's duties was insufficient and "the IMM's independence from the RTO would be questionable." Id. at 29).

entering into marketing monitoring contracts with multiple ISOs, which give rise to concerns that these firms may be spread too thin and not be able to give each region the careful attention required. In addition, some consulting firms are engaging in market monitoring activities in one region, while presenting testimony in RTO-related dockets in other regions on behalf of particular market participants, or have been hired by an RTO as an MM after previously presenting RTO-related testimony on behalf of the very transmission owners forming the RTO. All of these practices give rise to the appearance of lack of independence by such firms, and this in turn undermines their efficacy as MMs.

The VSCC therefore favors a requirement that an MM must be fully independent of all market participants, including the RTO/ITP whose markets the MM will be monitoring. The VSCC agrees with the Commission that an MM should not report to an RTO's/ITP's management. SMD NOPR at 55508, para. 430. The VSCC questions, however, whether the MM should have any special reporting relationship to the "independent governing board of the Independent Transmission Provider," as the Commission suggests. Id. Independent or not, the board is part of an RTO's/ITP's management; in fact it is the apex of its management. The board could well have the same incentive as management to avoid negative publicity for the RTO/ITP through the quashing of MM information disclosures or enforcement actions that might suggest problems in the RTO's/ITP's markets or operations. Hence, while the MM should certainly provide information and reports to the independent board, it should not *report* to it. Rather, it should report only to the Commission, those state public utility commissions in the states in which the RTO/ITP operates and other agencies involved in antitrust and market enforcement matters.

Additionally, consistent with the MM's confidentiality provisions, the MM's reports should be disseminated widely to all interested parties (e.g., state public utility commissions, Stakeholder Advisory Committees, etc.). Any person or entity applying for the position of MM should be selected through a process that involves all stakeholders (rather than just the RTO/ITP or the RTO/ITP and its transmission owners), and all applicants should be qualified through past experience to carry out the necessary duties. Funding of the MM should be sufficient to ensure that those personnel dedicated to this function need not accept other consulting assignments during the term of the engagement. An MM should only be removed prior to contract termination upon a showing of good cause and after Commission approval of such removal. The term of the engagement itself should be of sufficient duration to avoid the perception that the MM is a "short-timer," and therefore subject to pressure to suppress negative information regarding regional markets in order to obtain contract renewals.

The VSCC also believes that MMs should monitor regional bilateral markets and mitigate transactions in those markets whenever and wherever necessary to prevent the exercise of market power. The Commission in the SMD NOPR notes that participation in the ITP's Day-Ahead market is "voluntary," in that buyers and sellers do not have to buy or sell in that market. According to the Commission, the ITP's markets are "not intended to substitute for other longer-term arrangements that customers may use to purchase supplies such as bilateral transactions." SMD NOPR at 55489, para. 269. The Commission is proposing to require LSEs to comply with a Resource Adequacy Requirement ("RAR"), under which LSEs will have to enter into forward supply arrangements with generators, or risk associated penalties.[39] Paragraphs 474-476, 504-506. Hence, the power supply market in an RTO/ITP region will encompass a much larger universe of transactions than just those that take place in the RTO's/ITP's DA and RT markets.

Given this environment, the Commission's proposal that "[m]itigation would only apply to products traded in the spot markets operated by the Independent Transmission

[39] The VSCC's views on the RAR are set out below in Section III. J. Id. at 55512, paras. 474-476; Id. at 55515, paras. 504-506.

Provider, not to products traded under bilateral contracts outside the Independent Transmission Provider's spot markets" is dangerously insufficient. SMD NOPR at 55504, para. 404. The Commission believes that its blindered monitoring proposal would provide "the least intrusive framework for market power mitigation," while still providing "very effective protection against market power." Id. To the contrary, this framework would tie the MM's hands and prevent it from mitigating market power in the very market that the Commission intends to rely upon to ensure that adequate and reasonably-priced power supplies will be available to serve end users in the medium and long term.

The Commission states that MMs need not mitigate market power in bilateral markets, because "[b]ilateral contracts generally reflect buyer and seller expectations of prices in spot markets," and spot market price mitigation will thus "effectively discipline market power in bilateral markets as well." Id. at 55504-5, para. 405. This presumes that bilateral contracts will flow from spot markets and not vice versa. This might be the case for LSEs if they had the option not to purchase capacity and energy in bilateral markets and instead to wait until the day ahead to meet the bulk of their power supply needs. But LSEs cannot do this, nor would the VSCC want them to do so. LSEs have an obligation to provide reliable service to their retail loads. Waiting until day ahead or real time to purchase all or most of the power supplies retail customers need is just too risky a supply strategy to pursue. This would be particularly true in states that have not unbundled. Consequently, spot markets may in many places represent residual supplies after native load requirements have been satisfied with available resources.

Second, the Commission through its RAR proposal would require LSEs to contract forward in the bilateral market to meet their projected loads (plus a reserve requirement). It threatens LSEs that fail to do so with severe monetary penalties and actual curtailments. SMD NOPR at 55516-18, paras. 527-534. In such an environment, an LSE's failure to contract forward for power supplies would almost automatically raise questions of prudence regarding its power supply strategy.

In fact, the Commission has developed its proposed SMD to give bilateral contracts primary emphasis. It states at paragraph 10 of the NOPR that "[t]he short term spot markets set out below are intended to complement bilateral procurement." It believes that the reliance on bilateral contracts is "[c]entral to the Standard Market Design concept," and it has proposed the RAR to "strongly encourage" such long-term contracts." Id. at 55455. If the Commission does intend that bilateral contracts will be "central" to SMD, then it would be remiss not to have the MM monitor such markets.

In short, LSEs will not have the luxury to "just say no" to bilateral transactions, and sellers in those markets will know this. This in turn will create a potential disparity in bargaining leverage between buyers and sellers that opens the door to the potential exercise of generation market power by sellers in bilateral markets. Price mitigation in the RTO's/ITP's spot markets alone will not prevent the exercise of such market power. Only the presence of sufficient generation competition in bilateral markets among sellers will ensure that market power is not exercised. This is why the MM must be able to monitor bilateral markets and if necessary mitigate transactions in the bilateral markets to avert the exercise of generation market power, either local or regional.

The MM also must have access to the data that it needs to monitor transactions in all markets in the RTO/ITP's region and to discern patterns or practices that may tip off the MM to anticompetitive market behavior. The VSCC therefore supports Part IV.H., Sections 2.1.1, 2.1.2, 3.5 and 3.6 of the proposed SMD Tariff (Appendix B at Page Nos. 160, 162) Id. at 55569-70, which require market participants to comply with requests for information or data by the MM and to cooperate in any MM investigations or audits. The VSCC understands the reluctance of market participants to disclose to the MM sensitive data such as information on their fuel prices and generator heat rates, but this can be handled through appropriate confidentiality protections under Section 2.1.5 (Appendix B at Page No. 160) SMD NOPR at 55569. If the MM cannot obtain sufficient data regarding generator costs and inputs, then it cannot discern whether bidders into the

RTO/ITP's markets are submitting bids at or close to their marginal costs (thus indicating the presence of sufficient competition) or bids far in excess of those costs (indicating that problems exist with the RTO/ITP's markets).[40]

In addition, the MM must have full and complete access to all data in the possession of the RTO/ITP itself. Part IV.H., Section 2.1.3 of the SMD Tariff (Appendix B at Page 160) states that the RTO/ITP will give the MM "immediate access to all Bid data submitted" to the RTO/ITP, but does not make clear that the MM would have access to all data in the RTO's/ITP's possession. Id. The RTO's/ITP's responsibility to provide data should not be less than that of market participants, because the RTO/ITP itself is a market participant, at least to the extent that it operates power supply and ancillary services markets. If the MM is to monitor the RTO's/ITP's operations as well as those of other market participants (and the VSCC thinks that it should do so), then it needs full cooperation from the RTO/ITP in the provision of data. Id. at 55509, para. 432. The MM must therefore have full access to all RTO/ITP operating data and information, and ready access to the RTO's/ITP's employees. The RTO/ITP should be required to have a clear policy extending such access to the MM.

Wholesale supply agreements for generation needed to relieve transmission congestion should provide for price mitigation if the MM's structural analysis of the RTO's/ITP's markets and/or its monitoring activities indicates that a particular generation

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[40] See, e.g., PJM Interconnection, L.L.C., 101 FERC ¶ 61,135 (2002). There the Commission held that PJM's filing – which would have provided PJM's Market Monitoring Unit with greater ability to obtain information – exceeded the scope of its compliance obligation. The VSCC supports the concurring statement issued by Commissioner Massey, and would urge the Commission to adopt this approach in the SMD Final Rule:

> as a general matter, the RTO or ISO market monitors should be able to gather needed information in the most direct and least restrictive manner possible. The PJM MMU's ability to require responses to its requests should not be limited to certain situations or certain types of parties. As an independent entity, the MMU's request should be presumed reasonable unless the respondent shows the Commission that it is unreasonable. Id. at 61573.

unit's output is required to avert the exercise of local generation market power. But even more fundamentally, the Commission must require public utility sellers of power into the RTO/ITP's markets to show that they should be permitted to charge market-based rates in the first instance. The Commission cannot simply assume that sellers of power into RTO/ITP markets do not have market power or that any "residual" market power will be dealt with by the MM through mitigation in a PGA.

At present, the great bulk of public utility power sellers hold market-based rate authority that the Commission issued using the now-discredited "hub and spoke" test. Before even moving to implement SMD, the Commission and the regional MMs should conduct an in-depth structural analysis of each regional power market and the public utility power sellers in those markets. Market-based rate authority should only be granted to those public utility sellers that do not have generation market power in the relevant region. If a public utility seller does not have generation market power in the region, and thus qualifies for market-based rate authority, then particular units that the seller owns or operates that do enjoy local market power due to their unique locations or operating characteristics can then be dealt with through price mitigation in a specific PGA.

Finally, the VSCC is concerned about the definition of "Economic Withholding" used in Part IV.H., Section 3.2 of the SMD Tariff (Appendix B, Page No. 162) SMD NOPR at 55570. This provision defines Economic Withholding as "submitting high bids that are not consistent with the caps specified in Section H.1.2." Id. Section H.1.2. (Appendix B, Page No. 158) in turn sets out two applicable caps: (1) the "Safety-Net Bid Cap" in Section 1.2.1 (which the Commission proposes to set at the lofty level of $1000 per MW hour; P 413); and (2) the "Generator-specific Bid Cap" in Section 1.2.2 (the Commission in the NOPR provides no clues as to how such bid caps will be set). Id. at 55569.

If bidders into the RTO's/ITP's DA and RT markets consistently submit bids in excess of their own marginal costs, this is a strong signal that something is seriously wrong with the RTO's/ITP's markets, and that economic withholding in fact may be taking place. Yet, depending on how the Generator-specific Bid Caps are set, a generator could submit bids far in excess of its own marginal costs, and still not be in violation of the Economic Withholding prohibition set out in Section 3.2. (Appendix B, Page No. 162). SMD NOPR at 55570.

The Commission, unfortunately, appears to be willing to permit generators in RTO/ITP markets to collect such excess dollars, at least in the absence of binding transmission constraints. In NEPOOL, 2002 F.E.R.C. Lexis 2627, the Commission refused to approve mitigation measures that would have allowed ISO-NE to mitigate generator bids for unconstrained hours, even though the ISO had requested such authority. The ISO had argued that "even in non-constrained hours, the potential for some suppliers to exercise market power beneath the $1000/MW-hour cap cannot be dismissed," and that "mitigation measures remain important measures for New England's developing markets." Id. at 2646, para. 27. Nonetheless, the Commission did not grant the ISO this authority, saying, "the Commission will approve only mitigation measures that address well-defined structural problems in the market." The Commission expressed its expectation that "as markets mature," "underlying structural problems causing market power will be resolved, and at that point, behavioral mitigation rules can be removed." Id. at 2646, para. 28. The VSCC believes it is ludicrous to wait until abuses are considered "well designed structural problems" before meaningful action is taken. Much damage can be done before such a showing can be made.

The VSCC believes that such expectations are at best optimistic and at worst, shortsighted. RTOs/ITPs should have a full array of mitigation tools available to them if needed to address abusive or suspicious bidding behavior. The VSCC therefore suggests that Section 3.2 of the SMD Tariff, SMD NOPR at 55570, should be revised to state that generator bids showing a consistent pattern of exceeding marginal costs will be subject to the MM's scrutiny and potential *ex ante* mitigation. The MM should have the ability to apply *ex ante* mitigation to bids that are 10% in excess of the generator's marginal cost if the generator has a pattern and practice of submitting such excessive bids.[41] If the generator does not agree with the MM's mitigation of its bids, it would have the right to seek expedited Commission review of such mitigation.

For similar reasons, MMs should be able to exercise market power mitigation measures designed to protect end use customers from the payment of excessive prices during "extreme supply or demand conditions to which the market cannot quickly adapt, such as the loss of significant hydropower capacity because of drought, or force majeure events such as a major transmission line outage." SMD NOPR at 55506, para. 415. The Commission itself proposes such mitigation mechanisms, but would make them "voluntary." Id. The VSCC would support making such mitigation measures mandatory for each RTO/ITP. Just because they may be rarely employed does not mean that they are not useful or necessary.

Finally, the SMD Tariff should include language specifically prohibiting any activity that intentionally creates or exacerbates shortages or constraints, or intentionally creates the appearance of shortages or constraints where none in fact exist. Such language is necessary to deter gaming of ITP energy and transmission markets in cases

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41 In the past, generators have argued that their submission of bids in centralized spot markets that exceed their marginal costs should not be found to constitute economic withholding, because certain generators must recover their fixed as well as variable costs through bids that may only be accepted in a few hours during the course of an operating year. The imposition of an RAR, however, undercuts the force of such arguments. LSEs will have to contract forward with power suppliers in bilateral markets to cover their peak requirements on an ongoing basis. High cost generators supplying peaking power that opt not to enter into such forward contract arrangements, or that are not chosen by LSEs because their bilateral offers are simply uneconomic, have little economic justification for then submitting spot market bids substantially in excess of their marginal costs, to recover the same fixed costs that they could have recovered through forward contracts. Permitting such a practice would only create an incentive for such sellers to hold out for unreasonably high prices in bilateral contract negotiations. If LSEs must contract forward to meet their peak power supply requirements due to the imposition of an RAR, sellers of higher-cost peaking power must in turn be given some incentive to enter into such forward contracts. If there are bidders that wish to try to justify their bids in excess of marginal cost as needed to cover their costs, they should petition the MM, who will be in a position to judge whether their arguments have any merit.

where market participant ingenuity runs ahead of applicable specific market rules (as will likely often be the case). Such language would allow the MM to order market participants to cease and desist from prohibited activities, pending an expedited appeal to the Commission if the market participant contests the MM's interpretation of the tariff as applied to that participant's actions. In the absence of such a tariff provision, valuable time and dollars can be lost before an MM or the Commission could put a stop to an abusive market practice.

J. Long-Term Resource Adequacy

The NOPR assigns the responsibility for assuring resource adequacy to ITPs. In doing so, the NOPR opines that resource adequacy requirements must have a regional focus and must fit with competitive procurement. The VSCC agrees that long-term resource adequacy is important for reliable, competitive regional markets to ensure there will be sufficient supply and demand resources to avert shortages. It is not clear, however, that the NOPR's resource adequacy proposal would be the best means to meet long-term resource adequacy requirements that have generally fallen under state purview through state law.

The NOPR proposes that the ITP provide a forecast of the demand in its area, help the Regional State Advisory Committee ("RSAC") determine future reserve requirements, and assign each LSE a share of the needed future resources. The NOPR's resource adequacy proposal leaves many important questions unanswered. Specifically, the VSCC questions the practical application of the requirement in a retail access environment. It is very difficult to predict an LSE's loads over the long term accurately, as retail access programs get started and new entrants seek to gain customers. The VSCC is not convinced that the resource adequacy approach as set forth in the NOPR can be properly be applied in a retail access state or that it will provide additional benefits beyond those provided by existing state structures.

Although the NOPR indicates that the resource adequacy proposal is "designed to complement, not replace, existing state resource adequacy programs," it is not clear that state reserve requirements would be preserved under the new structure. The NOPR appears to indicate that a vertically integrated utility could be required by its state to satisfy a higher reserve standard and if the utility complies with the higher requirement, nothing further need be done. SMD NOPR at 55513, para. 480. While unclear, the NOPR seems to provide for sharing of such higher reserves across broader regions, in that it does not explicitly provide for a higher service priority to those LSEs that may have procured a higher level of reserves to comply with such higher state requirements. As a result, an LSE satisfying a more rigorous state requirement would have no additional priority and would have to share those resources across its designated region. In effect, under the NOPR a state-mandated higher reserve requirement would provide few or no additional reliability-related benefits to the state.

Furthermore, states like Virginia would have great difficulty in requiring higher reserves, given the practical problems of enforcing such reserves in a retail access environment. Competitive retail suppliers can serve scattered small customers whose demands are not directly measured. As such, it would be difficult, if not impossible, to enforce an RAR equitably. In addition, a higher state mandated reserve requirement would also serve as a barrier to entry into the retail supply market in that particular state. Further, the assignment of a physical scheduling right to holders of CRRs and the potential financial exposure of not having the right set of CRRs would impose even greater risks on potential new entrants into retail markets. Given the nature of retail service to smaller customers, retail suppliers may have a difficult time assessing the right mix of needed CRRs. Thus, the practical impact of the NOPR may be to remove many of the benefits of higher reserves, thereby causing all regions to migrate to the least common denominator. The RAR may substantially increase business risk for potential new entrants into retail markets when such entry is already quite limited.

Moreover, it is not at all clear that the Commission has any authority under the FPA to shift oversight of resource adequacy to the ITP, a regional entity under the regulation of the Commission. In such a regime, states' authority over generation resources would be diminished to their narrow participation in an advisory committee. As discussed above, section 210(b) of the FPA states that the FERC "shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction… over facilities used for the generation of electric energy…." Federal Power Act § 201(b), § 16 U.S.C. 824(b) (1994). As the NOPR recognizes, the states have traditionally had authority over resource adequacy, in order to ensure reliable electric service to the retail ratepayers located within their borders. In Virginia, for example, the Constitution and laws of Virginia direct the VSCC to ensure that reliable retail electric service is provided to all Virginia ratepayers. See e.g., Virginia Const. art. IX, § 2; and Va. Code § 56-234.[42]

The NOPR, however, limits states' roles in resource adequacy to their participation in the RSACs. Furthermore, the NOPR appears to indicate that the only role RSACs will have in resource adequacy will be to propose regional reserve requirements. The VSCC submits that such an encroachment into state authority and duties to ensure that reliable retail electric service is neither warranted, nor permissible under existing federal law.

Retail competition continues to develop slowly across the country, if at all. Thus, it is anticipated in Virginia that for some years to come most customers will take service from providers of last resort, which is likely to be incumbent utilities. Under Virginia's

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42 Article IX, § 2 , of the Virginia Constitution states "[s]ubject to such criteria and other requirements as may be prescribed by, law, the Commission shall have the power and be charged with the duty of regulating the rates, charges, and services and, except as may be otherwise authorized by this Constitution or by general law, the facilities of railroad, telephone, gas and electric companies." Virginia Code § 56-234 states "[i]t shall be the duty of every public utility to furnish reasonably adequate service and facilities at reasonable and just rates to any person, firm or corporation along its lines desiring same."

Restructuring Act, the VSCC may impose conditions[43] on the provider of last resort relating to adequate generation resources to ensure that reliable service is provided. If the Commission continues to assert that resource adequacy should be controlled through ITPs, (and the VSCC submits that such an assertion is improper), the Commonwealth of Virginia would lose key authority over ensuring reliable service in Virginia.

The VSCC believes that there is no clear legal authority under which the resource adequacy proposal in the NOPR can be implemented. Indeed, the clearest expressions in the FPA run counter to many of the SMD's proposals. The VSCC recommends that the Commission obtain legal authority clearly authorizing the implementation of a regionally based resource adequacy plan and then only after further details are developed specifically addressing how a resource requirement would be applied and the states' role in such a process.

K. State Participation in RTO Operations

The NOPR provides that various RSACs will be formed in order that states may have a "formal" role in the SMD decision-making process. Issues identified in the NOPR to be resolved by the RSACs are: 1) Resource adequacy standards; 2) Transmission planning and expansion; 3) Rate design and revenue requirements; 4) Market Power and market monitoring; 5) Demand response and load management; 6) Distributed generation and interconnection policies; 7) Energy efficiency and environmental issues; and 8) RTO management and budget review. SMD NOPR at 55519, para. 554.

To its credit, the Commission is seeking ways to create a state role in its SMD proposal. However, the authority under which RSACs are created is uncertain, and the intended purpose, authority, and structure of RSACs is equally unclear. Moreover,

[43] Virginia Code § 56-585 B 1.

RSACs' recommendations are not binding on ITPs or the FERC. Hence, a state's role within an RSAC is limited to its permitted voting power among the other regional participants.

As discussed more thoroughly throughout these comments, many of the issues addressed by the RSAC are issues of state or concurrent state/federal jurisdiction. The NOPR explicitly recognizes this fact. It is unclear how, in the absence of express legislative directive, issues falling under state and concurrent jurisdiction may be shifted to an undefined regional advisory committee.

The VSCC also believes that there may be barriers to its lawful participation in a regional advisory committee. Under the Constitution and laws of Virginia, the VSCC must perform specific, nondelegable, regulatory functions. In that regard, Virginia is unquestionably in the same posture as virtually every other state. Because the NOPR indicates that RSACs will decide issues of state and concurrent jurisdiction, based on "regional" goals, it is not clear—as a general matter—that the VSCC could lawfully participate in any such organization. The VSCC has the ongoing duty to further the public interest of Virginia ratepayers and to further the development of retail access in Virginia. In addition, Virginia's Restructuring Act has created a legislative committee, the Legislative Transition Task Force, to oversee the development of retail competition in Virginia. Thus, the VSCC believes that participation in RSACs could affect material issues relating to the implementation of retail competition in the Commonwealth and such participation may violate specific statutory provisions, including those relating to advancing retail access within Virginia's borders.

Thus, the regional advisory committee vehicle does not appear to be the best mechanism for providing solutions to issues of state and concurrent jurisdiction. At a minimum, further clarification as to the purpose, authority and structure of the RSACs is needed before states can provide any meaningful input as to the appropriateness of the proposal.

L. Governance for Independent Transmission Providers

The Commission Must Assure That An ITP Has Sufficient Operational Authorities to Ensure the ITP's Independence.

The Commission states that independence of the RTO/ITP is "critical to the successful implementation of Standard Market Design." SMD NOPR at 55520, para. 556. The VSCC absolutely agrees. The Commission further states that the governance requirements for the Board of Directors of the RTO/ITP are "critical to ensuring that the RTO is independent and that the RTO's interests are aligned with the interests of the market as a whole rather than with particular market participants[.]" Id. To accomplish this goal, the Commission proposes, among other things, to define more clearly define the responsibilities of the RTO/ITP's Board of Directors. Id. at 55520, para. 557. The VSCC agrees that a primary responsibility of the board should be, as the Commission states, "to ensure that the markets operated by the Independent Transmission Provider are operated in a fair, efficient and non-discriminatory manner." Id. at 55520, para. 558. The VSCC also agrees that "[t]he board should not be regarded as a partner or a contractor of the market participants." Id.

The Commission proposes a very detailed RTO/ITP board selection process to assure independence from market participants. Id. at 55521-2, paras. 562-568. The VSCC is not commenting on these details, except to note that some flexibility in board selection procedures may be desirable, so long as the end goal of board independence is attained. The VSCC instead urges the Commission not to miss the larger independence issue at stake in RTO/ITP formation. The Commission may leave a very big loophole in its policies if it allows the formation of an ITP that is by definition and corporate governance "independent" but which *lacks sufficient operational authorities to free it from the undue influence of the member transmission owners*.

To be truly independent, the RTO/ITP must have sufficient authority over matters going to the very heart of the process of operating the transmission system (e.g., operational control, reliability, and planning and expansion, among others). A good starting point for evaluating whether an RTO/ITP has sufficient operational authority is Order No. 2000, in which the Commission declared that "an RTO must have operational authority for all transmission facilities under its control and also must be the security coordinator [i.e., the NERC Reliability Authority] for its region."[44] The Commission should pay close attention to particular ITP/RTO proposals that contain one or more of the following trouble signs:

- Lack of Control over All Needed Transmission Facilities. An RTO/ITP must have the ability to control all the transmission facilities it needs to operate a regional transmission grid. If individual transmission owners retain the ability to withhold specific facilities from the RTO's/ITP's control at their discretion, they undermine the RTO's/ITP's ability to operate the regional grid on a non-discriminatory basis.

- Favored Treatment of Transmission Owners. The transmission owners must not be allowed to retain – through the guise of exclusive advisory committees with limited membership or similar devices – preferred access or operational authorities that would undermine the RTO/ITP's ability to control and operate their transmission facilities.

[44] Regional Transmission Organizations, FERC Stats. & Regs. p. 31,089 (1999), 65 Fed. Reg. 810 (2000), *on reh'g*, Order No. 2000-A, FERC Stats. & Regs. 30,092, 65 Fed Reg. 12,088 (2000), *aff'd*, Public Utility District No. 1 v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

- Lack of Ability to Reclaim Needed Functions from ITCs. If the RTO/ITP believes it necessary, it must have the ability to seek to reclaim functions previously delegated to an Independent Transmission Company ("ITC").

- Lack of Clear Authority to Perform Higher Level Control Area Functions. The RTO/ITP must have clear authority to perform higher-level control area functions, including, for example, serving as the NERC Reliability Authority.

- Subservient or "Coordinating" Role in Regional Transmission Planning Process. The RTO's/ITP's role in the planning and expansion process must not be subservient to the role of the individual transmission owners and ITCs within the RTO's/ITP's footprint. The RTO/ITP should be conducting a regional transmission planning process focused on the reliability and economic needs of the region, not just collating or "coordinating" the expansion plans of individual transmission owners and ITCs.

- One-Sided Terms in Contracts With ITPs. If a public utility chooses to meet its obligation under any SMD Final Rule by contracting "with an entity that meets the definition of an [ITP] to operate its transmission facilities" (Paragraph 125), the Commission must be able to review the terms of that contract and reject provisions that do not meet the standards of Order No. 2000. Certain types of contract provisions should raise red flags for the Commission, such as overly broad provisions for transmission owner termination of the ITP's engagement, or transmission-owner-determined ITP incentive compensation schemes.

IV. CONCLUSION

The VSCC concludes that both in concept and execution, the proposed rules are fundamentally flawed, and should be withdrawn by the Commission in favor of a thorough examination of the critical issues encompassed by them. Such a review should fully consider state and federal jurisdictional questions, as well as the costs and benefits associated with implementing the sweeping interposition of federal control over the nation's electricity system envisioned in this rulemaking. A second look and perhaps even more is required. Failing that, the VSCC respectfully requests the Commission to suspend its proceedings in this docket until it receives all necessary authority from Congress, and then to make the changes described above to its NOPR before issuing any Final Rule herein.

Respectfully submitted,

THE VIRGINIA STATE CORPORATION COMMISSION

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