UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Capacity Markets in Regions with Organized Electric Markets	))	Docket Nos. AD08-4-000

Alternative Market Design Proposal Informational Filing

The Portland Cement Association ("PCA"), is a trade association representing companies that produce Portland cement in the United States and Canada and who operate 107 manufacturing plants in 36 states and distribution centers serving all 50 states.

Mittal Steel USA, Inc., ("Mittal") is the North American division of ArcelorMittal NV, the world's largest steel company with steel making operations in 27 countries. Mittal is also the largest steel company in the United States and North America with operations in ten U.S. States, Mexico and Canada.

In support of the Technical Conference announced by the Commission under the subject Docket, the PCA and Mittal offer the attached additional information regarding the Alternative Market Design Proposal ("AMDP" or "Proposal"). In Appendix A, titled "Alternative Market Design Proposal For Just And Reasonable Electricity Prices", the basis for and goals of the AMDP are described and the processes outlined. In Appendix B, titled "Alternative Market Design Proposal – The Competitive Procurement Process", the auction and settlement process is described in more detail and a hypothetical

numerical example is provided. In Appendix C, titled "Alternative Market Design Proposal Frequently Asked Questions", questions that have been asked by interested parties are addressed to help explain more of the Competitive Procurement Process and to provide more background information regarding the basics of the AMDP.

The Proposal deploys competitive forces to obtain the lowest-cost combination of capacity and energy payments for consumers. This is a significant enhancement to the current market based pricing algorithms. The AMDP also provides incentives for individual generation units to recover their substantial investments and provide a return to their shareholders via unit-specific capacity revenues while recovering their variable operating costs through the variable energy revenues. Importantly, the combination of these payments would, on a unit-specific basis, provide the full return of and return on capital consistent with constitutional requirements but at a lower total cost to consumers. At the same time, the Proposal contributes to dynamic efficiency, by deploying algorithms and clearing mechanisms that seek the optimal procurement of energy and capacity based on the lowest possible combination of fixed and variable costs. Further, the AMDP offers features that would be substantial enhancements to the current form of centralized markets, our concerns with which we have addressed in previous filings.

Respectfully submitted,

Portland Cement Association
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April 30, 2008

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Appendix A
Alternative Market Design Proposal For Just And Reasonable Electricity Prices

Introduction

Disillusionment with cost-of-service regulation of the electric utility industry helped launch the United States down the path of competitive electricity markets. Competitive electricity markets offered the hope that market-based pricing and risk allocation would remove inefficiencies from the electricity supply and delivery system and thereby bring (in the long run) lower prices, innovation, and more customer focus. This has not happened. Instead of encouraging efficiency-enhancing infrastructure investments, energy price signals that are generated in the organized markets of ISOs and RTOs have discouraged investment, especially new baseload generation and transmission upgrades that relieve congestion. Instead, these market designs have enabled incumbent owners of both generation and transmission assets to experience unprecedented returns from the simple shift from regulated rates to single clearing price "markets," and any new investment in infrastructure upgrades will only reduce those returns. Additionally the single clearing price "market" models provide large incentives to generation owners for economic withholding. A pricing algorithm that rewards such anti-competitive behavior is inherently and fatally flawed (see "Merger Analysis In Restructured Electricity Supply Industries: The Proposed PSEG and Exelon Merger (2006)", by Frank Wolak and Shaun McRae, pp. 19-24, ftp://zia.stanford.edu/pub/papers/pseg_exelon_merger.pdf).

To "fix" the investment dilemma, generation owners pushed for the addition of new locational capacity auctions that give all generators (even the existing baseload units earning large infra-marginal energy revenues) capacity payments based on a theoretical marginal capital cost, in addition to energy payments based on the marginal fuel. These forward capacity auctions do nothing to promote new baseload generation investment because they lack the necessary long-term capital recovery for those investments. The current forward capacity auctions do not result in the type of long-term fixed price or cost indexed contracts that could support new entry and investment and would reduce the incentives for withholding inherent in single clearing price mechanisms.

These "fixes" have simply created an unprecedented transfer of wealth from consumers of electricity to owners of existing depreciated generation assets, while failing to attract the desired new generation investment. At the same time, new entrants find it difficult to compete in a world where there is no long-term certainty of capital recovery and where their new marginal units do not reap the infra-marginal energy revenue that depreciated baseload units reap. This model tends to drive investment decisions to the lowest capital cost solution – currently, natural gas-fired turbines - with minimal regard for the impact of such investments on energy prices.

A market model that pays windfalls to incumbent operators, but squeezes new investors, seems inconsistent with prudent national energy policy. Furthermore, greenhouse gas ("GHG") emission costs will tend to exacerbate the adverse impact on customers, if these costs are added to offers submitted by marginal units and thereby pass through to non-fossil generators in the market-clearing price. The market design is becoming increasingly out of synch with state policies that require low-cost solutions to pressing infrastructure, environmental, and customer rate challenges.

Traditional approaches to pricing electricity establish rates based on the fixed costs of a utility's assets over the life of the assets. Variable costs (including fuel costs) are generally passed through, without mark-up, to customers. This approach ensures that consumers pay only the utility's average costs while the utility earns a fair return on (and of) its investments. However, this approach to electricity pricing provides utilities with an incentive to over-build in an effort to increase invested capital and therefore their return. Overbuilding results in sharp, unnecessary rate increases and underutilized capacity. Some "over-investment" was the result of the "lumpiness" of generation capacity additions that, at times, were substantially larger than a single utility system might have needed to cover near-term load growth. However, even with "lumpy" investment, cost of service rates moderated over time because the depreciated book value of older assets in rate base helped ameliorate the rate impact of the higher book value of the new assets. The gradual addition of new investment to depreciated assets typically ensured that customers were getting value for their capital contributions, enjoying the benefits of depreciation, and paying rates lower than required in today's organized markets where they pay as if all units are priced at the new-build cost.In several of today's organized markets, by contrast, single clearing price capacity auctions result in merely a one-year commitment and price, which results in pricing that never reflects the price-ameliorating effect of the depreciated book value of older assets. Moreover, these approaches to market design depart from the markets that have evolved in other capital-intensive industries, in which commodity markets do not include separate marginal clearing price mechanisms for production capacity and actual volumetric production.

The Alternative Market Design Proposal ("AMDP" or "Design") outlined in this document recognizes that a utility system is planned and operated on the basis of long-lived, capital-intensive capacity resources (kW), not merely energy (kWh). The Design proposes the use of competition and market forces, where those dynamics can be used to drive efficiency, to set capacity prices and manage capacity additions. The AMDP also proposes to use market forces in energy markets by layering in cost-based dispatch options for RTOs that remove a supplier's incentive to attempt to affect energy market clearing prices through withholding, while recognizing the need for pricing on a locational basis. However, like the cost-of-service model, capital recovery payments by customers will assure those customers that they pay variable costs based on actual costs, not the bid submitted by the least efficient unit. The combined effect of this capacity and energy payment structure would be to provide generation owners with a reasonable opportunity to collect revenues commensurate with the revenue requirement of their units while insuring that consumers receive some value for their capacity payments from fuel diversity and improved supply system efficiencies. This structure for capacity and energy pricing, with the potential for zonal differences based on real transmission constraints, also reflects the electrical topology of the system.

This Design attempts to create reasonable economic opportunities for both buyers (e.g., LSEs and large customers) and suppliers to negotiate long-term bilateral contracts that would, over time, expose consumers to prices that more closely reflect long-run marginal costs, rather than to prices that reflect the recurring recalculation of short-term marginal costs.

In order to support new entry and investment, however, the Design retains the existing function of some RTOs as a default aggregator of load in order to reduce counterparty risk for generation developers and to enhance the efficiency of the overall system by integrating the transmission planning process into the generation supply auctions over a broad geographic area. The Design depends, as it must, on transparent integrated resource planning of the entire system and integrating transmission planning with the generation procurement process.

An average capacity pricing methodology that delivers energy at fair and reasonable prices, if properly implemented and administered, would provide consumers a much lower all-in delivered cost than that available in any of the current wholesale pricing designs in place in RTO regions. The ultimate goal is to equilibrate revenue opportunities for owners of existing depreciated assets and owners of new generation assets by injecting competition in the selection of generation resources (both new and existing) as long-term resources and in the dispatch of energy imbalance markets across broad geographic areas, while restoring the consumer benefits of generation asset depreciation, fuel diversity, and improved operational efficiencies. In short, the goal is an improved balance between the needs of investors and consumers than what is provided with the current market design of single clearing price energy and capacity markets. If successful, then individual states will look to regional markets and RTO processes for solutions to their long-term needs, instead of retreating to or fiercely defending state-specific or utility-specific procurement approaches.

Alternative Market Design Proposal Outline

This Alternative Market Design Proposal begins with the premise that RTOs deliver value to customers by performing, independently and more transparently, certain functions that were previously performed by monopoly transmission owners. RTOs should continue to perform these functions. A proposal advanced by the American Public Power Association ("APPA"), at page vii of its recent document "Consumers in Peril: Why RTO-Run Electricity Markets Fail to Produce Just and Reasonable Electric Rates," captures these essential functions as follows:

- Ensure non-discriminatory access to the grid through independent administration of a regional OATT and provision of transmission service, including needed ancillary services.

- Develop and administer a regional transmission rate design that eliminates rate pancaking and assures the recovery of the cost of transmission facilities for all transmission facility owners that wish to participate in the RTO, regardless of their form of ownership.
- Operate a single regional open access same-time information system (OASIS) and independently calculate available transmission capacity (ATC).
- Conduct independent and collaborative regional transmission and generation interconnection facilities planning, with the full inclusion of affected stakeholders.
- Carry out wide-area system security and reliability-related activities, ensuring that transmission facilities are operated in compliance with relevant North American Electric Reliability Corp. and regional reliability entity criteria.
- Operate an energy imbalance market to enable transmission customers to manage their imbalances and to allow generators (including intermittent renewable generators) to sell excess generation not committed under bilateral contract arrangements.
- Ensure adequate generation reserves through implementation of appropriate regional resource adequacy requirements.

The Design below expands on the last two bullet-points on the APPA list (i.e., procuring an efficient mix of generation resources and operating a cost-effective energy imbalance market).

1) Load Forecasting and System Modeling

a) RTOs/ISOs, in coordination and cooperation with state planning and state siting authorities pursuant to a transparent process, shall have primary responsibility for developing integrated transmission and generation modeling/planning.
   i) Modeling/planning results should be released annually
   ii) States, wholesale customers, and industrial customers should have the ability to demonstrate to RTOs/ISOs that they have adequately self-supplied resources to satisfy resource adequacy requirements.
b) Load forecast procedures for future Regional Transmission Planning Processes (RTEPP) and for the Competitive Procurement Process discussed below should:
   i) Account for changes in peak load, energy volumes, load duration, and others factors critical to long-term planning
   ii) Use the same set of assumptions for an integrated approach to generation, transmission, and demand resource planning
   iii) Consider state commission and other stakeholder input regarding planning parameters
   iv) Determine local deliverability requirements based on transmission transfer limits and generation characteristics under peak system load conditions.
   v) Utilize existing RTO/ISO Security Constrained Unit Commitment (SCUC) dispatch models.
c) Through this planning process, the RTO/ISO will identify the region's needs for generation capacity and long-term demand response resources, and any reliability-based operating or locational characteristics that are necessary for these resources

2) Competitive Procurement Process

a) The Competitive Procurement Process will apply to all load for which LSEs have not demonstrated, to the RTO/ISO, long-term arrangements for delivering energy to meet load levels during the peak period.
b) The first Competitive Procurement Process would be held soon after implementation of the new market design, and Competitive Procurement Processes would be held every 2 years thereafter, unless the RTO determines that a Process must occur more frequently.
c) The number of years before obligations are imposed on units procured through the Competitive Procurement Process shall be determined by the RTO based on actual performance in the industry, based on, among other things, the type of generation that is procured (i.e., baseload, intermediate, and peaking).
   For example:
   (1) Obligations on peaking units incurred through Competitive Procurement Process take effect no earlier than 3 years after the Competitive Procurement Process is conducted.
   (2) Obligations on intermediate units incurred through Competitive Procurement Process take effect no earlier than 5 years after the Competitive Procurement Process is conducted.
   (3) Obligations on baseload units incurred through Competitive Procurement Process take effect no earlier than 7 years after the Competitive Procurement Process is conducted.
d) Selected units receive revenue recovery assurances over the long-term (10-20 years) via a FERC tariff, consistent with their remaining useful lives, as reflected in their capacity offers.
e) The Competitive Procurement Process for each forward year would procure the needs identified by the planning process discussed above, but would procure less than the full reserve requirement, due to the inherent uncertainty of load forecasts and the pricing implications of procuring more than is needed; the difference between the initial procurement of generation and demand response resources for a given delivery year and the full reserve requirement for that delivery year would be procured over time by “Incremental Residual Auctions” (IRAs) closer in proximity to the delivery year.
f) Generation that is not receiving compensation for long-term capacity obligations would be subject to a must-offer requirement into the Competitive Procurement Process, in the form of market-based capacity bids with cost-based energy bids (i.e., $/MW-day with a cost-based strike price of $/MWh); market-based capacity bids should reflect a commitment length consistent with the remaining useful life of the unit; cost-based energy bids must show unit heat rate and unit operational characteristics.
g) The objective function of both the Competitive Procurement Process and IRAs is to procure supply at the lowest cost to consumers for the planning period.
h) Long-term, unit-specific approach to procurement and pricing should reduce the need for mitigation due to a more level playing field for new entry, but some areas with concentrated generation ownership and limited ability for new entry will require that capacity offers reflect the actual cost of existing units (including appropriate amortization of actual fixed costs) if, and for as long as, those units

are needed for system reliability, as determined by a properly structured Market Monitor.

3) Clearing Process and Payments to Suppliers

a) Consistent with the objective function above the Competitive Procurement Process, the IRAs, and unit dispatch would produce the overall lowest cost supply to customers.
   i) The unit selection process/algorithm will consider and select units based on the combination of capacity and energy prices that will result in the overall lowest cost to customers over the relevant planning horizon.
   ii) Optimization and unit selection in the procurement process must be synergized with transmission planning objectives.
b) Units selected in the Competitive Procurement Process receive unit-specific capacity payments and unit-specific "cost plus" energy payments with indexing to account for changes in fuel and variable O&M costs.
c) Units receiving capacity payments would be subject to liquidated damages (LDs) for non-performance of energy delivery when dispatched (e.g., LDs equal to LMP replacement cost).
d) Balancing markets (Day-Ahead and Real-Time) would continue on a very limited basis for residual energy, and would be dispatched at LMP; however, only those units not receiving a capacity payment would actually collect LMP on a clearing price basis. Any unit receiving capacity payments would collect only its actual fuel and variable O&M costs associated with the dispatch of their rated capacity.
   i) Any energy production beyond the contracted capacity of a unit would also receive LMP on a clearing price basis.
e) Equal access to transmission system for new and existing units; deliverability determined by offers and transfer limits

4) Load Costs

a) Customers would pay MW-weighted zonal prices for capacity and MWh-weighted zonal prices for energy because energy and capacity would mostly be paid “as bid”.
b) Customers would not pay the LMPs produced in the Day-Ahead and Real-Time energy markets for **all** energy consumed from those markets because the LMPs would be paid only to units that are not receiving capacity payments.

Appendix B

Alternative Market Design Proposal: The Competitive Procurement Process

Forward Capacity and Energy Bidding, Auction and Settlement Processes

Load Forecast and System Dispatch Model:

Some form of modeling and planning is essential to the reliable operation of the electric system and is performed by every RTO/. The RTO would develop a system load forecast in the same manner as it does today for transmission planning purposes. This load forecast today is the basis for the Regional Transmission Expansion Planning Process (RTEPP). Under the Alternative Market Design Proposal ("AMDP") this load forecast would become the basis of an integrated Resource Adequacy Plan ("RAP"). The RAP would model the system over the planning period based upon forecast loads, stakeholder input and state directives. Part of the RAP would be an identification of future needs that must be met via transmission or generation additions or through demand response. The RAP would not be proscriptive but rather identify a need for resources either systemically or locally within the planning period time frame.

Competitive Procurement Process - The Auction Process:

Based upon the needs (if any) identified in the annual RAP, the RTO would conduct an auction to procure capacity on a long term basis (10 to 20 years) to meet the forecasted load. The auction would clear based on running a Security Constrained Unit Commitment ("SCUC") dispatch model of the system just as they do today in evaluating transmission expansion projects with 20 plus year lives. Reserve margins would be added incrementally in years closer to the delivery year, but the initial need identification could be as far as 7 years out to allow for the opportunity for new baseload generation to compete effectively.. The advantage of an increasing reserve margin is that it helps to reduce the risk of over procurement through forecast error. It also tends to push the solution in years 2 and 3 to existing generation, new peaking or intermediate units or curtailable loads while the longer term auctions remain more open to base load generation construction. All auctions are actually residual because the resulting 10 to 20 year supply obligations result in a rolling portfolio of contracts such that each auction is essentially procuring only replacement capacity for expiring obligations and capacity for load growth rather than the entire system requirements being re-priced each year. Initially existing asset obligation terms would be based on the remaining useful lives of the assets in order to mitigate their ability to exert market power and to manage the "lumpiness" issue associated with the transition to the AMDP.

Locational deliverability is required to the extent that there are transmission limitations under forecasted peak conditions. The use of the SCUC above allows the locational

deliverability element to be factored into the auction process. Capacity offers are submitted with energy to be supplied at a unit specific strike price of variable production cost plus 5% by existing or potential generating units and loads willing to commit to curtail. The same forward fuel price forecasting methods that the RTO uses today for transmission planning would be employed. Unit specific strike prices serve two purposes. First they reduce the inherent incentive in single clearing price auctions for withholding. Secondly, they are intended to create more of an averaging of the energy costs, similar to the old world of imbedded average fuel costs, while allowing for economic dispatch of the system using essentially the existing LMP dispatch models to achieve the desired economic efficiencies without the wealth transfer tht happens under the current structures. The difference would be in how the generator is financially settled, not in the economic dispatch order. There would be less mitigation required for the capacity offers because in a forward auction where new entrants and a responsive demand curve can freely compete there would finally be real competitive forces.

Competitive Procurement Process - Clearing Process and Payments to Suppliers:

Solution of the auction's SCUC computer algorithm by the RTO/ISO would be to determine an overall least cost supply portfolio (in the same manner as the models operate today) to serve the forecasted RTO/ISO system load using the capacity offers and the energy strike prices and using forecasted hourly energy requirements. The forecasted hourly energy requirements would be developed in the same manner as the peak forecasts by applying growth factors to actual historical data and normalizing for weather. Such a system wide least cost solution might include selection of an uneconomic unit in one zone if it produces an overall least cost solution for the overall system.

The amount of unit specific capacity that is locationally deliverable outside its local zone would be determined based on the potential to economically supply energy throughout the year in a manner that produces a least cost solution for the system. In this way new entrants gain equal access to the existing transmission grid so that consumers benefit from the lowest possible energy supplies whether from existing or new generation resources. A unit with a low capacity price might not get selected in favor of higher capacity offers if the higher capacity offers includes enough lower cost energy that is deliverable often enough to offset the higher capacity cost. In this way base load generation construction is encouraged in a manner that makes it deliverable to loads in as many hours as possible.

When the AMDP competition winning bidders are selected, the selected units would enter into binding 10 to 20 year supply obligations at the capacity offer and energy strike prices according to a FERC filed tariff that allows the RTO to then collect those dollars from Load Serving Entities (LSEs) in the RTO. Curtailable loads would only need to be committed for the auction year in which they are selected since there is no value to "depreciating" load curtailments but longer term curtailment commitments could be utilized to help finance load control project costs if the loads desired such. The energy strike price for generators could be indexed to the specific fuel cost for that unit or the supply offer could include a fixed energy strike price if the supplier chooses to hedge their fuel costs for some or all of the forward contract period. Suppliers (generators or

curtailable loads) would be paid their offer prices for capacity and energy except for loads using their curtailments to offset their obligation as described above. Existing and new units would compete head to head to serve the total system load, creating an incentive for an existing unit to offer capacity at a reduced rate, reflecting the depreciated asset value rather than new construction costs, given that it has to compete against newer more efficient units and responding loads. When the system is tight, new construction costs would be the logical clearing point for the capacity offers, but when there is excess existing generation capacity owners are rewarded for offering their capacity at less than new construction costs, helping to bring down the overall cost for consumers to something that resembles an imbedded capital cost. The long term forward obligation also provides the benefit of locking in capacity prices for a period of time that prevents clearing prices from always approaching new construction costs on average and has a stabilizing effect on consumer costs.

Competitive Procurement Process - Settlement Process and Load Costs:

Capacity auctions would provide system or zonal prices for capacity that would be collected from LSEs serving loads in the actual delivery year based on the average price for the capacity that is associated with a given zone proportioned based on the energy delivered from each unit to each of the zones to which it delivers energy throughout the model year. Capacity costs for LSEs would be determined based upon the total zonal payments throughout the initial and subsequent residual auctions. Bilateral and self supply transactions would be facilitated by being offered into the auction at $0/MW and $0/MWh offers to be assured of clearing. Loads using bilateral transactions or self supply would be excluded from the calculation of the average capacity cost per MW that remaining loads would pay to the RTO.

The energy strike price is a financially binding commitment to provide energy at that price but it is still desirable to have residual energy imbalance markets. The imbalance energy markets, real time and day ahead, would continue to be operated and clear in the same manner as they do currently (LMP basis), however any energy that comes from a unit or portion of a unit that receives a capacity payment would have to be offered at the strike price and those units would only receive their strike price for the energy. In that way loads or LSEs buying energy in the imbalance markets would pay the average cost of the energy supplied to their zones, including both the energy supplied at the cost based strike prices and any energy procured at LMP by the RTO. This allows all units to be economically dispatched, providing the benefits of broad regional dispatch to consumers, but does not over compensate base load generation suppliers by paying them a marginal peaking or intermediate unit price for their energy unless the base load unit is receiving no capacity payments for some reason. Self supply and bilateral transactions would not affect the payments or prices for other LSEs since they are submitted with a $0 strike price.

The combined effect of the capacity and energy payments above would be to collect something akin to an imbedded cost of capacity and an average energy cost with the potential for zonal differences based on real transmission constraints. At the same time competitive market forces are brought to bear in the auction process since existing and

new generation units are treated on an identical basis and the energy dispatch includes all units regardless of whether or not they have a unit specific strike price.

Example:

In this hypothetical example the transfer capability is limited to 100 MW between adjacent zones, but there is no direct transfer capability between Zones 1 and 4 or between zones 2 and 3. The baseload generation in Zone 1 all clears from an energy standpoint, but in order satisfy the reserve margin and peak deliverability requirements the Zonal generation as shown in each of the zones is required. The table below shows a hypothetical solution to a Competitive Procurement Process where there is sufficient transfer capability to not have price separation in capacity, but during peak hours there is energy price separation.

Zone 1 200 MW Load 400 MW Generation 1. 200 MW @ $500/MW-day & $15/MWH 2. 200 MW @ $400/MW-day & $30/MWH	Zone 2 300 MW load 300 MW Generation 1. 200 MW @ $350/MW-day & $35/MWH 2. 50 MW @ $270/MW-day & $75/MWH 3. 50 MW @ $150/MW-day & $125/MWh
Zone 3 300 MW Load 300 MW Generation 1. 200 MW @ $300/MW-day & $55/MWH 2. 100 MW @ $150/MW-day & $125/MWH	Zone 4 200 MW Load 150 MW Generation 1. 100 MW @ $270/MW-day & $75/MWH 2. 50 MW @ $125/MW-day & $150/MWH

Capacity Prices: $/MW/day

Zone 1	Zone 2	Zone 3	Zone 4
$329.78	$329.78	$329.78	$329.78

Peak Hour Energy Prices: $/MWH

Zone 1	Zone 2	Zone 3	Zone 4
$22.50	$37.14	$55.71	$60.71

Capacity offer prices were based on new construction costs of coal, nuclear or natural gas simple and combined cycle facilities. Load in each zone pays the weighted average of

the capacity payments required to serve its annual energy requirements, and energy prices are set through the LMP process, except with a financially binding settlement on the contract for differences associated with any capacity that is obligated through the forward Competitive Procurement Process. Notice that all zones benefit during peak hours from having unit specific strike prices based upon actual operating costs yet no generation supplier selected is revenue deficient unlike what happens under current wholesale pricing algorithms in the organized markets. In this manner resource adequacy is assured at a much lower cost to consumers, even assuming 100% new construction costs, than under current pricing methods and generation suppliers earn their desired returns.

Competitive Procurement Process - Conslusion:

The proposed Competitive Procurement Process uses market forces to set capacity prices and manage capacity additions. It also uses market forces in the LMP energy markets but layers in cost based contracts for difference that reduce a suppliers incentive to withhold while preserving the economic signals that LMP is supposed to provide. It is however dependant upon an integrated planning model of the entire system, significant stakeholder and state input and integrating transmission planning with the Competitive Procurement Process. In the example above, a 100MW transfer capability built between Zones 1 and 4 would completely alter the energy market results.

A zonal average capacity cost methodology that comes with energy at something close to actual unit cost gets consumers to a just and reasonable delivered cost better than any of the current competitive wholesale market structures in place in the US while leveling the playing field between existing generators and new entrants to an extent that no RTO has achieved. Allowing all generation (existing and new) to be eligible for a capacity payment (effectively a call option premium), but in exchange requiring the associated energy to be provided at cost plus allows the benefits of competitive markets to accrue to consumers while still allowing new generation entrants to compete on a level playing field with existing rate based or formerly rate based units. The ultimate goal is to inject more robust competition in the selection of generation resources and in the dispatch of energy imbalance markets across broad geographic areas while not losing the benefits of depreciating generation assets, fuel diversity and improved operational efficiencies that consumers have lost under the current flawed wholesale pricing structures.

Appendix C
Alternative Market Design Proposal
Frequently Asked Questions

Q. Is the proposed Market Design an attempt to re-regulate electricity supply?

A. No. To the contrary, the model is a true competitive framework that was designed after 10 plus years of experience with the current single clearing price computer algorithms. The model was designed to fix electricity markets by introducing real competitive forces into resource selection, while eliminating or at least minimizing the inherent anti-competitive aspects of the current clearing price algorithms. The current electricity supply pricing algorithms not only fail to produce real competition between suppliers, but in every case reward economic withholding (see Dr. Frank Wolak, ftp://zia.stanford.edu/pub/papers/pseg_exelon_merger.pdf). In every region, suppliers' profit-maximizing behavior is to economically withhold supply, and bid data posted by RTOs supports this observation. One of the primary goals in developing a competitive electricity supply market was to create real competition. Some sellers who are accustomed to the current market design may not support a truly competitive market, but the diverse group of industrial and large commercial end users who developed this Alternative Market Design have learned from our own businesses that only when we finally see real competition in electricity supply will the benefits of competitive electricity supply promised in Order 888 be realized by consumers. That is why we developed a market design that features the deployment of competitive forces in the electricity supply process to replace the current noncompetitive computer algorithms that exist now.

Q. How would the auction process work?

A. The RTO would develop a load and resource forecast based upon the best available planning parameters (much like they do today). These plans would include all existing generation resources that are currently under obligation and any retirements and contract terminations. The plan would identify any future need for resources. The RTO would operate competitive auctions for the needed amount of “resources,” allowing new generation, existing generation, transmission expansions, or demand response to compete to satisfy the identified need. The RTO would select the resources that produces the least-cost mix of resources over the planning period. If cleared, resources would be committed to supply capacity and energy consistent with their offers and the RTO would obligate loads to pay, similar to how the centrally operated capacity mechanisms operate today.

Q. Who would develop the planning parameters and load and fuel forecasts?

A. A stakeholder process, to include market participants and state regulators, would be a critical component of the planning process. The other key part of the process will be the RTO's independent analysis and results, as a starting point for stakeholder discussion. This process would allow a state that wants to impose specific goals for renewable resources or reserve margins to do so at the start of the auction process and to revise the parameters annually or as needed. Existing transmission capacity would be available to all market participants equally, with no preference for existing units, with the exception that units already committed through earlier Competitive Procurement Processes would be assured of the transmission capacity to deliver energy to the system. Consequently, in any auction, no preference would be granted to an old, possibly inefficient existing unit for the available transmission capacity in the area. This produces a more competitive result than current pricing structures because the older unit would have to behave competitively, in the face of new entrant competition, to secure the necessary transmission capacity to deliver its energy to the system.

Q. What would suppliers be paid for capacity?

A. Suppliers would be paid a capacity price that reflects their unit-specific offers. Because auctions would be held far enough forward to allow new entry, less mitigation should be necessary.

Q. What would suppliers be paid for delivered energy?

A. Suppliers would be paid their unit-specific energy strike price. Because the auctions include unit-specific capacity and energy offers, the energy strike price is a financial obligation to perform. If a unit fails to deliver when dispatched, it would be obligated to supply at its strike price or make customers financially whole, essentially Liquidated Damages.

Q. Why does the Design include unit-specific prices?

A. No competitive market operates like the current electricity pricing algorithms with a single clearing price for production capacity **and** a single clearing price for the volumetric production. Some markets have volumetric only pricing that LMP algorithms are supposed to emulate, while others combine production capacity and volumetric pricing in customer-specific competitively sourced contracts. Because electricity has been recognized to be different, we have distinct capacity and volumetric rates. However, setting both of these rates on a single clearing price basis has resulted in a substantial overcollection of money from loads and provides incentives for economic and physical withholding that produce anticompetitive behaviors by suppliers in all of the centrally operated pricing mechanisms.

Q. Why does the Design include long-term obligations?

A. In developing the Alternative Market Design, we wanted to create a truly competitive market for electricity and move away from administrative “market

based" algorithms. The current pricing algorithms are deficient because they reduce if not outright prohibit competition. New entrants have difficulty under current rate setting mechanisms because they do not have "financeable" obligations. Long-term obligations that ensure capital recovery through a FERC backed RTO tariff should allow greater competition and new entry. The second anticompetitive element of the current mechanisms that we were striving to address are the incentives in single clearing price mechanisms for economic and physical withholding.

Q. What would loads pay for capacity?

A. Loads would pay the weighted average of the resource capacity costs associated with the units required. To the extent that there are deliverability issues, there could be zonal or location differences in capacity costs with those costs being allocated based upon where they are required.

Q. What would loads pay for energy?

A. Loads would pay the weighted average of the actual energy costs associated with the units running in any given interval. To the extent that there are deliverability issues, there could be zonal or location differences in energy costs. The current LMP dispatch algorithms would still be necessary for units that are not receiving capacity payments and to dispatch the system based on unit-specific strike price obligations.

Q. How is demand response treated?

A. Demand response is essentially peaking capacity and would be treated similar to a peaking unit with the ability to offer into the auction process and clear or to essentially be a price taker. In this way, demand response would truly be afforded comparable treatment without the need for any special incentives. If demand response does not clear in the Competitive Procurement Process, it would be eligible to bid into the LMP segment of the energy market and receive the clearing price like any other resources that have not cleared in the Competitive Procurement Process.

Q. What process would be necessary to implement the Alternative Market Design?

A. The Alternative Market Design would require changes in RTO tariffs and some changes to RTO software. One would expect that, because LMP is being retained in some form for dispatch and limited pricing purposes, and because much of the infrastructure being used for centralized capacity mechanisms should be of some value in the Competitive Procurement Process, implementation would not obviate prior investment and existing infrastructure.

Q. What is the primary obstacle to implementation?

A. The primary obstacle to implementation is likely to be the opposition expressed by incumbent suppliers whose revenue streams will be brought back into closer alignment with their actual costs plus reasonable returns on their investments. So, in essence, the primary obstacle to implementation may simply be the political will to implement “just and reasonable” wholesale electricity pricing. Viewed differently, if all stakeholders were in favor of implementing this Design, it is likely that implementation could be accomplished no later than the end of next year.

Q. Has this design been used elsewhere?

A. The core of this Design is the Competitive Procurement Process, which been used by a number of states and is even required by some state statutes as utilities identify the need for additional generation capacity. The Design provides additional advantages relative to the procurement processes employed by states, however, because it operates from a regional perspective, will tend to avoid "lumpiness" concerns that arise within a single state or utility company territory, and is coordinated by an independent entity, while still allowing states and LSEs to make their own decisions about resource adequacy, if they choose. The Design incorporates many of the useful aspects of competitive procurement processes being used by several states, while recognizing that RTOs can and should provide play a key role in achieving larger scale efficiency for the benefit of customers.

Q. Is the Design limited to the "organized" markets?

A. Not necessarily. While the Design was conceived and developed as a near-term solution to the pricing problems that result from single clearing price capacity mechanisms such the Demand Curve in New York, the Forward Capacity Market in New England, and the Reliability Pricing Model in PJM, the Design could be deployed to provide customer benefits elsewhere. For example, a coordinated regional approach to resource procurement could help address the "buy vs. build" decisions that are occurring with increasing frequency in the Southwest Power Pool region. The Design could also facilitate the utilization of newer, higher-efficiency generators in the Southeast and the Design would be a relatively easy incremental solution for California to implement as a Resource Adequacy construct.