UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Compensation for Generating Units Subject to Local Market Power Mitigation In Bid-Based Markets PJM Interconnection, L.L.C.	Docket Nos. PL04-2-000, EL03-236-000

Comments of Steven B. Corneli
On Behalf of
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Thank you for inviting me to address the important issues of market power mitigation, reliability-must-run units, and compensation. NRG is a major owner of competitive generation in constrained areas of PJM, New York, and Connecticut and is familiar with mitigation, RMR issues, and related market design needs. We deeply appreciate this opportunity to address the Commission on such critical issues.

If there is one theme emerging in this technical conference, it is that the critical policy issue in constrained areas is not that prices are too high due to market power; it is that prices are too low due to incomplete and flawed markets. I will make four basic points that address this problem with respect to the specific topics set for this panel. In addition, I have prepared written comments on the overall questions to be addressed by the conference, which I will leave for your consideration.

The four basic points are these:

First, **there is good evidence that the exercise of market power does not take place in any of the three northeastern markets**. The definition of market power is sellers' ability to raise and profitably sustain prices above the competitive level. There is no better definition of competitive price levels in resource-constrained areas than the range of prices needed to produce, on average, the long-run marginal cost of needed investment. These are prices that a well-structured competitive market will, and indeed must, produce to keep supply and demand in balance. In each of the three northeastern markets, ISOs or their market experts consistently report that average prices do not exceed, and in key constrained areas fall short of, the levels needed for efficient new investment to recover its full costs. Thus there is no evidence of market power abuse. Instead, there is strong evidence that prices in areas that critically need additional generation investment fail to even cover the cost of critically needed existing investment. The implication is startling and clear – the critical policy need is not the mitigation of supplier market power in constrained areas. The critical need is the correction of market design flaws that create a persistent and dangerous under-recovery of costs by needed investment. If not corrected, these flaws will threaten reliability, increase consumer costs, and threaten the future of a competitive electric industry. This is a problem that should concern everybody in this room.

Second, it is increasingly evident that **aggressive mitigation is not needed to prevent generators in constrained areas from extracting monopoly profits**. If there is one lesson to be learned from the Commission's experiment with PUSH bidding in constrained areas of NEPOOL, this is it. Under PUSH bidding, generators in a load pocket with significant concentration of ownership have been allowed to bid up to levels approaching the $1000 bid cap, such bids rarely set prices and, as a result, have not supported fixed cost recovery, much less the exercise of market power. Yet for energy prices to, on average, produce the needed long-run marginal cost signal, they must at times reach very high levels, because they are certain at other times to fall to very low levels.

Again, the policy focus needs to shift from prices that are too high due to market power, to prices that are too low due to market design flaws. Market power is associated with extraordinary profits and barriers to entry. By contrast, constrained areas in NEPOOL are associated with extraordinary losses and barriers to exit. While the NEPOOL market sends price signals to power plants in Boston or Connecticut that say "exit now," the NEPOOL market rules read like the fine print at the Hotel California – "you can check out any time you like, but you can never leave." As long as this is the case, the Commission must recognize the need for both existing and new investment to recover their costs outside of the NEPOOL market. And PJM is not far behind, with explicit recognition in a 206 filing to this Commission that its market design is likely to lead to underinvestment in constrained areas, and active consideration of prohibitions on retirement for units "needed for reliability". Focusing on mitigating price signals while putting up a fence to keep the "guests" from leaving is not a good policy agenda. Far better would be to modify the market platform so that needed generators want in instead of out.

The third point brings some good news. Despite these serious design flaws, **tried and true market solutions do exist**. The New York ISO's combination of mitigation and other measures that support moderate scarcity prices, a locational ICAP market, and the capacity demand curve concept -- due, in large part, to the vision and leadership of the New York Public Service Commission – work together and have the potential to send the needed long-run marginal cost signal to buyers and sellers alike, while preventing any exercise of market power. While these elements need some fine-tuning, they already are creating incentives for LSEs on Long Island and in New York City to issue RFPs for competitive procurement of independent power that will lower costs and enhance reliability in these constrained areas. This same basic package of market design elements – locational capacity, a capacity demand curve, and moderate mitigation – will work in NEPOOL and PJM as well.

Which brings me to my final point -- **infrastructure**. The northeast needs infrastructure. Existing generation is needed to maintain reliability and for secure power supplies. New generation is needed to enhance reliability and relieve congestion. Transmission investment is needed for the same purpose, and to accommodate new generation. But without decisive action to quickly modify the flawed market designs of NEPOOL and PJM, competitive generation will not be able to contribute to these infrastructure needs.

Consumers and competition will suffer, as regulated monopoly infrastructure investments slowly creep in to replace competitive alternatives, without the benefit of the synergies, cost reductions, innovation, and efficient allocation of risk that competitive markets provide.

Detailed Questions
Technical Conferences
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1) What is local market power and why should it be mitigated? When should a supply offer be mitigated?

The standard definition of local market power is the ability of a supplier to profitably set and sustain market price above the competitive level. For this definition to be useful, the concept of "the competitive level" must be understood in the context of economic theory and business reality. Many observers believe that the competitive level is equal to the incremental fuel and other tangible production costs of the last unit dispatched for energy production. This view is inconsistent with standard textbook economic theory and will prevent competitive businesses from receiving the prices needed to attract and maintain needed levels of investment.

Economic theory, and basic business experience, both teach us that competitive firms decide to invest based on whether competitive prices, on average, are expected to equal or exceed the long-run marginal cost of investment. Only if competitive price levels average out to at least the long-run marginal cost of investment will needed investment be made and sustained. This means that competitive price levels are those levels that attract and sustain needed investment. Prices and revenues consistently below that level, when supply and demand are in balance or when additional supply is needed, are anti-competitively low. Prices that persist indefinitely above that level are anti-competitively high. The lesson here is critically important – the Commission should design its mitigation and RMR policies to produce average prices that equal long-run marginal cost at the level of investment required to maintain reliability. The idea that prices and revenues should only cover approach long-run marginal cost levels in conditions of "scarcity" is wrong, and will lead to persistent under-investment.

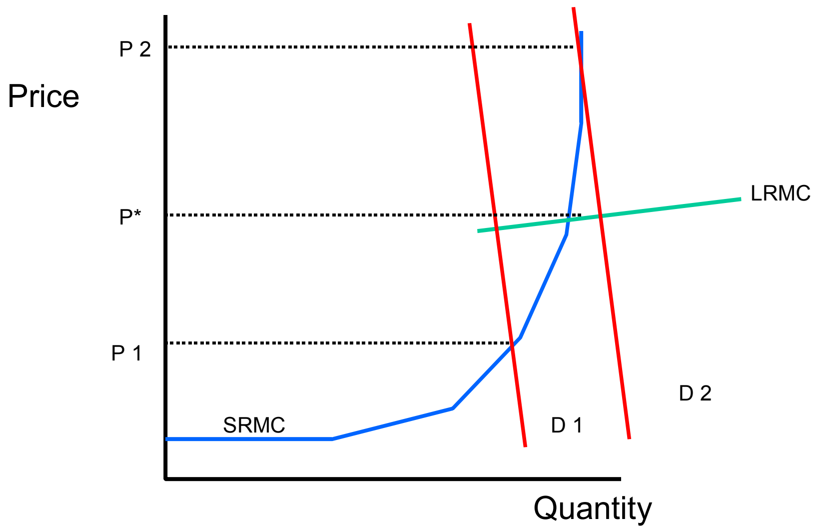
The long-run marginal cost at a location is the full fixed and variable cost of efficient, new investment built there. For example, if a new peaker has fixed costs of $80,000 per MW-year, and if it runs 800 hours per year, its fixed costs are $100 per MW-hour. Its fuel and other variable costs, by contrast, are about $60 per MW-hour. Even though this plant will run whenever prices exceed $60 per hour, it must face prices that ***average*** $160 per MW-hour in order to recover its fixed costs. Otherwise, it has no incentive to enter or remain in the market. If this unit is needed to achieve or maintain supply in balance with demand, those prices – prices that *average* $160 per MW-hour – <u>are</u> "the competitive level."

Note that capping prices at $160 would completely fail to produce such competitive prices. For example, let's assume that this new, efficient and needed facility is a price taker at $60 in half the hours it runs, or 400 hours a year. Then it needs to recover its full fixed costs in the other 400 hours it runs, which means prices in those hours must **average** $260 per MW-hour in order to be competitive. And that average is itself almost certain to require prices well in excess of $260. For example, if the RTO's economic dispatch in 200 of these hours produces prices of $160 per MW-hour, then in the other 200 hours, prices must average $360 for the prices to be "at the competitive level."

Thus those who argue that the competitive price level equals the fuel plus variable O&M of existing facilities would find that any offers in excess of $60, or one-hundred ten percent of $60, or that produce prices above some arbitrary threshold but less than $360, are an abuse of market power – when all those prices are clearly below the competitive level, and thus cannot *by definition* be an exercise of market power.

The conclusion is, and has to be, that "the competitive level" is a broad range of prices that, when realized by the interaction of bids, scarcity pricing measures, and demand, produce average prices that approximate the prices needed for new, efficient and competitive investment to recover its full fixed and variable costs – wherever and whenever additional supply is needed or current supply must be maintained to keep supply and demand in balance. The occasional high prices needed to create average prices that recover the full cost of needed investment **must** be far greater than the incremental fuel cost of any resource, and instead must reflect the entire system's short-run marginal cost of meeting demand without violating security constraints, including measures of producer and consumer risk and opportunity cost.

These conclusions are illustrated in the following diagram. Here, the short-run marginal cost of production increases as total output increases, becoming near-vertical at high levels of production. Prices are set where short-run marginal cost intersects with demand, or the marginal benefit of consumption. The long-run marginal cost is less than the highest short-run marginal costs, but more than the lower range of short-run marginal costs. At periods of high demand (D2), prices are set on the vertical portion of the marginal cost curve, far above the highest variable fuel and O&M costs of the last generating unit dispatched, e.g. at P2. During periods of lower demand, prices are set at the much lower short-run marginal costs of P1. Only if the average of prices at and between P1 and P2 is at least as great (P*) as the long-run marginal cost (LRMC) in the market will new and existing investment be able to recover its cost. When such investment must be made or maintained, prices should not be mitigated below P2, because such mitigation will drive average prices (P*) below the LRMC level needed to attract and retain needed investment.



Long-Run and Short-Run Marginal Costs and Competitive Price Levels

Any mitigation measure must recognize and support such prices, or it will falsely identify competitive price levels as evidence of market power, will mitigate bids to below competitive price levels, and will produce prices that are too low to attract and sustain needed competitive investment. Further, it will do all this based on an intellectually bankrupt notion – that "the competitive level" is always the short-run variable cost of the last unit dispatched.

Thus bid offers should not be mitigated unless there is a clear trend, over time, towards average prices that would exceed the amounts needed for fixed cost recovery. Any more aggressive mitigation than this will reduce prices below competitive levels, will fail to consistently identify and correct market power, and will quench investment, unless alternative means are in place and can be relied on to create sufficient revenues for needed investment to recover its fixed costs and a return. For example, properly-designed means to reflect reserve shortages (and extraordinary actions the ISO takes to avoid reserve shortages) in energy prices can help create high energy prices during times of high demand, while appropriate capacity or "resource adequacy" requirements can create payment streams for capacity that, together with energy and reserve revenues, allow needed generation to recover its costs. Indeed, because a certain amount of oversupply is required in electricity markets to ensure reliability, energy prices are unlikely to reach levels that would attract and sustain needed resources, even without any mitigation, unless supply levels were allowed to fall below the levels required for reliability.

2) What are load pockets and what infrastructure is needed to resolve them?

Load pockets are electrical regions that have higher merit-order (that is, more costly to dispatch) electric generation in them than outside of them, and that also have transmission constraints that limit the use of the less expensive generation outside of the load pockets to meet demand or operate the system in a secure manner. As a result, load pockets rely on the more costly dispatch of the local generation to operate the system in a secure manner. Some load pockets, but by no means all, also face a general shortage of generation, inside or outside of the load pocket, that can be relied on to prevent generation-related loss of load standards.

The first kind of load pocket does not "need" any infrastructure, and there is nothing that necessarily must be resolved. The question is purely an economic one – are there infrastructure investments that would reduce the cost of achieving a secure dispatch (i.e., the cost of congestion) by more than the cost of the infrastructure investments themselves? If so, a well-designed market should attract such investment. However, a load pocket in a market that suppresses prices below long-run marginal cost through excessive mitigation, a lack of scarcity pricing, and no locational reserve or capacity pricing, will not attract competitive generation resources even if they could cost-effectively reduce the cost of congestion. Such a market flaw should be corrected by a relaxed mitigation scheme and by creating a local capacity market, and potentially local reserve markets, that will cover the costs of the most cost-effective competitive solution. Once such competitive solutions face proper incentives, transmission planning can identify the needed transmission upgrades and their interaction with the competitive candidates. However, it very well may be that the least costly solution is the status quo – some constraints are cheaper to live with than to try to remove.

The second kind of load pocket, however, needs additional investment to meet reliability criteria. The fix should be the same as in the economic congestion case – if it is well designed, the wholesale market will attract the needed investment, while making it easy to identify the most cost-effective transmission upgrades. However, prolonged market dysfunction, as continues to be experienced in New England, and as is emerging as a problem in PJM, makes it likely that excessively expensive, regulated solutions will be selected instead of more efficient competitive alternatives.

Market power is not a necessary problem in load pockets, either. First, the ability to set price, as discussed above, is not in and of itself indicative of any market power problem at all, unless the price that is set exceeds, over time, the competitive levels needed to attract and sustain needed investment. Further, the concept that a "pivotal supplier" is able to exercise market power in load pockets is excessive – what determines whether a specific unit can set price is whether that unit faces competitive alternatives in its bids to be committed or dispatched. This is not a function of how many other facilities the generation owner controls, but is instead a function of how many other independent suppliers are potentially on the margin in the LMP auction. Both experience and theory suggest that a very small number of competitors can impose sufficient bidding pressure to prevent price-setting behavior in load pockets, so that the "pivotal supplier" analysis can overestimate the potential for price-setting behavior. Such price-setting behavior, however, is not an exercise of market power unless it meets the long-run marginal cost definition explained above.

3) What are the goals of local market power mitigation, and how do they fit with the goals of attracting and retaining needed infrastructure investment?

The goals should be:

- to prevent strategic physical withholding,
- to promote equilibrium pricing that supports and attracts needed investment, and
- to apply clear, correct and logically consistent economic and business thinking to problems that unfortunately have a strong tendency to be distorted by politics and their intrusion into the regulatory process.

4) When does scarcity occur within a local area or load pocket?

There is no bright line between ordinary economic prices and scarcity prices. Perhaps the best way to think about the difference is that, when demand is very high, both producers and the system as a whole face short-run marginal costs that begin to significantly exceed the variable fuel and O&M costs that reflect short-run marginal costs when supply is ample relative to demand. Thus bids may begin to drastically exceed previous levels when there is a high degree of risk of generation outages (leading to a short position in real-time at potentially very high prices), while system operator actions, such as reducing reserve levels, dropping voltage, asking for voluntary load shedding, etc., also reflect extremely high short-run marginal costs. These indications of scarcity, if they are not reflected in extremely high LMPs, will chronically and systematically prevent the higher prices needed to approximate a LRMC price signal.

a. What distinguishes between short and long-term scarcity?

The key distinction is how persistent and expensive the scarcity conditions identified above are. If they persist so long or rise to such levels that it would cost less to construct new facilities than to continue to incur such costs and risks, the scarcity condition is a long-run condition, in that it would be cheaper to expand the overall investment in plant and equipment than to continue to manage with existing plant and equipment. A well-designed market would prevent such long-run scarcity conditions from ever occurring, by sending appropriate price signals that induce appropriate competitive levels of maintenance and construction of needed facilities.

b. How does one distinguish between scarcity pricing and monopoly rents?

It is critical to remember that monopoly rents are extraordinarily high profits. Thus the first test should be whether a supplier in a load pocket is realizing extraordinary profits – that is, revenues that substantially exceed all of the supplier's costs, including the cost of risk, locational rents associated with real estate and infrastructure, and a competitive return. This test cannot be made based on whether bids or prices exceed variable costs. It can be considered through the sort of net revenue analysis market monitors conduct in the three northeastern markets, which compare available market revenues to the full cost of new entry. In areas without generation surpluses, monopoly rents would be indicated only if market revenues are significantly in excess of the full cost of new entry.

If suppliers are losing money in load pockets, despite prices and bids above variable costs, they are clearly not producing monopoly rents. In the long run, any such prices are not above "the competitive level" and thus are not indicative of an exercise of market power, unless average prices exceed the market's long-run marginal cost over a time period that is long enough to allow entry.

5) How is infrastructure developed in load pockets?

All investment, whether competitive or regulated, is developed in response to expected returns. Those returns must reflect the various risks – including market, regulatory, and technology risk -- associated with investment. One way to minimize those risks is for a willing buyer, who wishes to avoid the risk of high congestion costs, scarcity prices, high capacity costs and other supply risk, to enter into a contract with a willing supplier, who wishes to avoid various market and regulatory risks. Price signals that produce, on average, the long-run marginal cost of investment and that are allowed to exhibit sufficient volatility around, meaning both above and below, this average will provide sufficient incentives for such contracting.

However, a buyer that can get energy and capacity at suppressed prices in the local ISO spot markets will have little or no incentive to pay the full cost of new investment. Further, a buyer who needs to get regulatory approval at the state level to pass the costs of the contract on to its customers may face additional disincentives to contract. However, with well-designed competitive markets, intermediaries should emerge who are willing to manage these risks. Such competitive, bilateral contracts could have many of the characteristics of current RMR contracts in the absence of such counter-parties.

What may be the most effective course of action is to (a) encourage such bilateral contracts by immediately instituting market designs that produce long-run marginal cost recovery; (b) by doing so, also encourage states and LSEs to support long-term contracts; and in the meantime (c) allow RMR contracts for needed facilities that demonstrate financial losses, in order to provide fixed cost recovery and thus support long-run market dynamics in the absence of such market design and bilateral contracts.

6) What are the options for local market power mitigation?
   a) Bid Offer caps
      a. Unit-specific
      b. Seller-specific
      c. Region-specific
   b) RMR contracts
   c) Other

If the long-run marginal cost test is failed, then some sort of offer mitigation is warranted.

The least intrusive and most logically consistent mitigation would be a **regional** option like the current "safety net bid cap" at $1000 per MWH that limits the level to which prices can move during periods of extreme demand, while permitting the underlying short-run marginal cost pressures to operate effectively in a zone that has at least some potential to produce long-run marginal cost signals in the energy market.

If a more aggressive approach to mitigation is deemed necessary, then it should be carefully designed to preserve high levels of scarcity pricing during periods of high demand when mitigated bids set energy prices. This can be done through a **unit-specific** approach, as has been advocated in the Midwest and New York markets by David Patton. This approach requires the creation of reference prices that reflect the very high short-run marginal cost of certain units or top-end levels of output from certain units under conditions of high prices and high risk of failure. Mitigation to these reference prices during periods of high demand will simulate the real short-run marginal cost based prices that an efficient and well-designed energy market platform would induce, while preventing price-setting behavior that some may suspect could lead to the actual creation of monopoly rents.

Even with these approaches, the energy market is likely not to produce the long-run marginal cost signal necessary to attract and retain needed investment, for two reasons. First, the required planning reserve margins needed for reliability is in effect an engineered oversupply, and is thus likely to suppress prices below levels needed to stimulate entry and maintain existing facilities. Second, especially in the face of this engineered oversupply, energy prices would need to occasionally reach extremely high levels, levels that far exceed the $1000 safety net bid cap. For example, ISO-NE estimated in 2002 that it would have approximately 20 hours during 2003 in which emergency actions under its OP-4 rules would be necessary to prevent loss of load. These are key hours in which significant scarcity pricing is warranted. For a new peaker that costs $80,000 per MW to recover its fixed costs in those 20 hours, prices would have to be over $4,000 per megawatt-hour.

As a result, it is critically essential that market design create additional revenue streams outside of the energy market to provide the needed long-run marginal cost signal to attract and maintain needed investment. Locational capacity markets, together with other non-energy revenues such as locational reserves, are essential to attract and maintain needed levels of investment.

Even more aggressive mitigation measures, such as PJM's, are designed to ensure that supplier bids in constrained areas cannot possibly set prices at scarcity levels during periods of constraint. Such mitigation measures find support among those who erroneously think that "the competitive level" always means prices equal to the variable fuel and O&M costs of the last plant dispatched, as well as among buyers who preferred prices that are suppressed below true competitive levels. Such aggressive mitigation needs compensatory capacity markets, with a locational component to target investment to areas where it is needed most and where the mitigation hinders local scarcity prices from arising in the energy market.

Finally, RMRs certainly control market power by limiting producer's revenues to their costs. Further, in the absence of well-designed energy, reserves, and capacity markets, RMRs may be necessary to keep needed suppliers in business. The rule of thumb here should be simple: if a needed facility cannot retire without jeopardizing reliability, and if the ISO's market design has flaws that do not permit it to recover its full costs, then it should receive an RMR contract that does recover its full costs.

In the "other" category, perhaps the best means to ensure fixed cost recovery and to mitigate against market power is for LSEs to enter into long-term contracts that provide financial or physical hedges against high energy prices, in return for bilateral capacity payments that support the construction and maintenance of needed facilities.

7) Which roles are appropriate and preferred for the following entities, and who should be responsible for addressing local market power and infrastructure development?
    a. Should RTOs and ISOs:
        i. Administer markets that appropriately value resources over time and location?
        ii. Administer local market power mitigation measures?
            1. What degree of discretion is appropriate?
        iii. Develop and enforce capacity obligations?
        iv. Negotiate contracts (e.g., RMR contracts) and auctions for resources?
    b. Should LSEs
        i. Have the responsibility to procure sufficient resources including in load pockets?
        ii. Pay for resources that RTOs and ISOs procure on their behalf?
    c. State commissions
    d. FERC

The FERC has both the responsibility and the authority to ensure that RTO and ISO markets create prices that are just and reasonable. In a market context, this means that expected prices in equilibrium, or as equilibrium is approximated by variations in supply and demand, should cover the full long-run costs of needed investment. Market design that falls short of this objective may satisfy interest groups on the buying side of the market in the short run, but in the long run will lead to higher prices, jeopardized reliability, and a persistent skepticism of the electric industry and the Commission's vision on the part of capital markets.

The Commission should act decisively to ensure that RTO and ISO market design meets the long-run marginal cost criterion, recognizing that interest groups on the buyers' side of the market will complain persistently and effectively about moving to economically efficient prices. This will be especially true in places like the constrained areas of

NEPOOL, where buyers have enjoyed subsidized capacity and reliability services for so long that generation adequacy and reliability are seriously threatened.

The design and administration of mitigation programs is critical to meeting this long-run marginal cost criterion. As discussed above, mitigation must be based on an accurate and sensible definition of "the competitive price level" that recognizes that competitive prices must reflect long-run marginal costs rather than simply the fuel and variable O&M costs of production. Any mitigation scheme needs to be accompanied by a well-designed capacity market – that is, with locational requirements and "demand curve" characteristics to stabilize prices and reflect the benefit of supplies above the minimum required level – in order to meet the long-run marginal cost criterion. Perhaps most important, the Commission must ensure that the design of mitigation, capacity markets, and related revenue streams work together to produce the needed long-run marginal cost signal.

LSEs must have the obligation to meet their customers' load plus required planning reserves. Otherwise, LSEs will have strong incentives to be free-riders due to the public good characteristics of capacity, reliability, and spot market stability. But in addition, LSEs must face spot market signals in energy and capacity markets that properly reflect the long-run marginal cost, as well as the short-run marginal cost of meeting demand in a reliable manner, or they will have no incentives to contract for new supply.

State commissions that retain authority over their LSE's rates should facilitate their LSEs' participation in both spot markets and efficient bilateral contracts, by understanding and applying the long-run marginal cost criterion in their own prudency reviews. Such a criterion is consistent with state-sponsored RFP and competitive procurement policies, which themselves will benefit from the existence of an efficient capacity or resource adequacy market that provides a benchmark against which to judge regulated acquisitions and other infrastructure investments.

What approaches produce price signals and market structures that attract investment in load pockets?

e. Relax market power mitigation
    i. Safe harbor bid adders (e.g., PUSH)
f. Local installed capacity obligations (LICAP)
    i. Enforcement through capacity deficiency rate
    ii. Enforcement through spot price penalty
    iii. Duration of obligation
g. Pricing of the value of operating reserves (scarcity pricing) State-approved curtailment plans
h. Infrastructure related Credit Issues

Answered above. A combination of relaxed mitigation, LICAP and scarcity pricing for actions taken to avoid reserve shortages is needed.

8) For transparent market prices to attract and retain needed investment where and when needed, should these prices reflect:
    a. Short run marginal cost
    b. "Going forward" cost
    c. Long run marginal cost
    d. Sunk investment cost
    e. Other

Long-run marginal cost recovery is needed for efficient new investment and to retain efficient existing investment. A competitive firm that recovers only its going forward costs in a market that should be clearing at long-run marginal cost (far above going-forward costs) is incurring a significant loss due to regulatory and market design failure, and should be allowed to exit the market.

9) Are long-term commitments necessary for investment in infrastructure (generation, transmission or demand response) to resolve or remove load pockets?

Yes, if resolution is warranted – that is, if the cost of relieving the constraints is less than the cost of congestion. However, these commitments need not be mandated, as bilateral markets can produce long-term contracts in response to upside and downside risk for buyers and sellers produced by well-designed spot markets for energy and capacity.

10) Under what conditions is an RTO-administered auction to acquire capacity in a local area warranted?
    a. Who can call for an auction?
    b. What resources will be able to bid into auction? Transmission? Existing generation units? Demand Response?

Any time the RTO considers economic or reliability expansion, an auction process is appropriate. A supplier who needs an RMR should be able to call for an auction in a market that does not have LICAP provisions. The auction result could set a market clearing price, to give the auction key LICAP characteristics. However, the auction must be able to make an accurate, fair, and comparable evaluation of alternatives.

11) What are appropriate combinations of the market power mitigation measures and the local resource adequacy measures?

They should produce revenues that add up, under realistic conditions, to cover the cost of needed investment, and be responsive to overall supply and demand levels. The demand curve approach allows this total revenue amount to decline appropriately in the event excess supply develops, and to increase as relative shortages in supply appear.