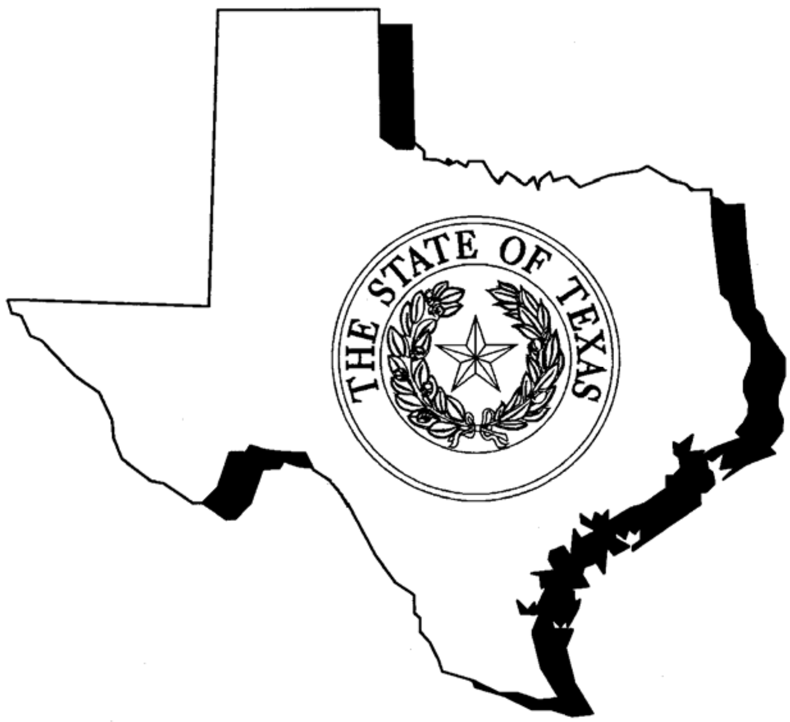
Staff Exhibit 1

DOCKET NO. 31540

PROCEEDING TO CONSIDER	§	PUBLIC UTILITY COMMISSION
PROTOCOLS TO IMPLEMENT A	§	OF
NODAL MARKET IN THE ELECTRIC	§	TEXAS
RELIABILITY COUNCIL OF TEXAS	§	
(ERCOT) PURSUANT TO P.U.C. SUBST.	§	
R. 25.501	§	



DIRECT TESTIMONY OF

DAVID B. PATTON

PRESIDENT,
POTOMAC ECONOMICS LTD.

ON BEHALF OF THE PUBLIC UTILITY COMMISSION OF TEXAS STAFF

NOVEMBER 10, 2005 – CORRECTED DECEMBER 4, 2005

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DAVID B. PATTON

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and current position.

A. My name is David B. Patton. I am an economist and President of Potomac Economics. Our offices are located at 4029 Ridge Top Road, Fairfax, VA 22030. Potomac Economics is a firm specializing in expert economic analysis and consulting.

Q. Please briefly describe your professional experience.

A. I have worked as an energy economist for fifteen years, focusing primarily on the electric utility and natural gas industries. I manage and direct the firm's work as the Independent Market Monitor for the Midwest ISO. In this role, we are responsible for identifying and remedying flaws in the market design or attempts to exercise market power. I also serve as the Independent Market Advisor for the New York ISO and ISO New England and an Independent Advisor to the Public Utility Commission of Texas regarding the ERCOT markets.

I have also provided strategic advice, analysis, and expert testimony in the areas of electric power industry restructuring, pricing, mergers, and market power. With regard to competitive analysis, I have provided expert testimony and analysis regarding market power issues in a number of mergers and market-based pricing cases before the Federal Energy Regulatory Commission ("FERC"), state regulatory commissions, and the U.S. Department of Justice.

Prior to my experience as a consultant, I served as a Senior Economist in the Office of Economic Policy at the FERC, advising the Commission on a variety of policy issues, including transmission pricing and open-access policies and electric utility mergers. Before joining the FERC, I worked as an economist for the U.S. Department of Energy. I hold a Ph.D. and M.A. in Economics from George Mason University and a B.A. in

Economics with a minor in Mathematics from New Mexico State University. Attachment 1 provides a more detailed description of my professional background.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Public Utility Commission of Texas ("Commission") Staff.

Q. What is the purpose of your testimony in this case, Docket No. 31540, *Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas (ERCOT) Pursuant to Subst. R. 25.501?*

A. The purpose of my testimony is to evaluate the market design proposed in this docket. I focus on major design elements and, therefore, do not address minor design details or attempt to validate the settlement formulas in the protocols.

Q. How is your testimony organized?

A. Each section of the testimony provides a discussion and recommendations on different areas in the nodal protocols. Section II addresses the Day-Ahead Market, Section III addresses the Reliability Unit Commitment, and Section IV addresses the Real-Time Markets.

II. DAY-AHEAD MARKET

A. Background

Q. What is your overall opinion regarding the day-ahead market proposed in the protocols?

A. In general, the protocols propose a day-ahead market that is likely to produce significant economic benefits for the ERCOT market by improving the efficiency with which resources are committed to meet the demands of the market for the following operating day. The proposed day-ahead market is part of a "multi-settlement" market framework, which means that energy and ancillary services are settled first through the day-ahead market and then deviations from the day-ahead market schedules are settled through the real-time market.

Q. What is the key function of the day-ahead market?

A. Using three-part offers that fully reflect both the costs of committing resources (i.e., bringing and keeping the resources online) and the costs of dispatching resources (i.e., producing electricity from the resources), the day-ahead market minimizes the costs of satisfying the as-bid energy and ancillary services demands. This market-based coordination can be expected to produce more efficient results than the decentralized commitment of resources by participants that occurs under the current ERCOT zonal market design.

Q. What factors lead to good performance by the day-ahead market?

A. A well-functioning day-ahead market will result in market outcomes that closely converge with the real-time market outcomes. This is achieved by designing a day-ahead market that allows participants to flexibly increase or decrease their energy and ancillary services purchases and sales. Perhaps the most significant features of the proposed day-ahead market in this regard are the provisions that allow participants to make energy-only purchases and sales at any location within ERCOT. For example, participants without a generating resource can submit energy offers at a location in the day-ahead market that would result in a day-ahead energy sale and a corresponding real-time energy purchase. For the purposes of this testimony, I will refer to energy purchases and sales in the day-ahead market that do not correspond to physical resources or loads as “financial energy transactions”.[1] Financial energy transactions are important because they are one of the primary means by which participants arbitrage the prices in the day-ahead and real-time markets. This

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[1] In other nodal markets, these transactions are referred to as “virtual supply” and “virtual load”.

arbitrage can also occur by adjusting the bid and offer quantities or prices associated with physical resources and loads in the day-ahead market.

Q. Other than promoting convergence between the day-ahead and real-time market, what other benefits do financial energy transactions provide?

A. Financial energy transactions mitigate market power in the day-ahead market. If owners of physical supplies withhold them in the day-ahead market to raise prices, other participants will increase their financial energy sales or decrease their energy purchases to prevent prices from rising significantly. This occurs because participants can profit by selling energy at the higher day-ahead prices and buying back the energy in the real-time market at lower prices.

B. Offer Caps

Q. Please comment on the offer caps in the day-ahead market?

A. The protocols propose an array of offer caps for supply offers made into the day-ahead market. In general, offer caps are intended to prevent suppliers from economically withholding resources to raise prices. However, generic technology-specific energy offer caps in the day-ahead market, which are not currently included in the protocols, would not substantially affect the outcomes of the market, for two reasons. First, attempts to withhold will be undermined by the financial energy transactions and reduced energy purchases by loads. Second, any strategy by a generator to raise the offer price for its energy can by implemented by submitting a high-priced energy bid to purchase energy at the generator's location. For example, selling 500 megawatts ("MW") from a generator and purchasing back 300 MW at the generator's location with a high-priced energy bid would result in a net day-ahead sale of 200 MW (500-200 MW). This is equivalent to selling 200 MW from the generator by economically withholding 300 MW from the generator.

Q. Do you recommend adding generic technology-specific energy offer caps in the day-ahead market?

A. No. As described above, generic technology specific energy offer caps do not provide significant protection to the day-ahead market. However, they can cause problems. For example, the offer cap may cause some suppliers not to offer their resources in the day-ahead market. This would be likely for suppliers that perceive a relatively high cost associated with committing to sell their energy in the day-ahead market (i.e., higher than the energy offer cap).

Q. Will the absence of generic technology-specific energy offer caps put load at risk of incurring significantly higher costs in the day-ahead market?

A. No. As long as market power in the real-time market is effectively mitigated, the natural market incentives to arbitrage prices between the day-ahead and real-time market will prevent artificial inflation of the day-ahead prices. For example, if prices are expected to be $100 per megawatt-hour ("MWh") in the real-time market the next day based on fundamental factors, prices in the day-ahead market will not rise significantly above $100 per MWh, because financial energy sellers will sell energy and loads will reduce their day-ahead purchases.

Q. Are the start-up and minimum-generation caps also extraneous?

A. No. While energy is a financial commodity in the day-ahead market that can be supplied by participants with or without physical resources, physical commitment requirements (which I later recommend be included in the day-ahead market) can only be satisfied by suppliers with physical resources in appropriate locations. The commitment of their resources to satisfy these capacity requirements should be based on the resources' commitments costs, comprised of their start-up and minimum-generation costs. Therefore, one could argue that the start-up and minimum-generation offer caps can affect the market by helping ensure that the generation commitment patterns are efficient. If these caps were removed, mitigation measures would need to be imposed that prevent suppliers with market power from exercising it by offering very high commitment costs for resources that must be committed to meet ERCOT's capacity requirements.

C. Local Reliability Requirements in the Day-Ahead Market

Q. Are there any other significant changes you recommend to the day-ahead market?

A. Yes. Every market that I have worked with in the U.S. has areas that are subject to locational reliability requirements. In general, these tend to be load centers that are subject to chronic transmission congestion or voltage issues. These local reserve requirements generally require that a minimum quantity of resources be online in the local area to allow the area to reliably respond to the largest transmission or generation outage (i.e., contingency) that could affect the area (and sometimes the second-largest contingency as well). Local reserve requirements include any requirements invoked to ensure that load within the zone can be satisfied reliably. It is important for the markets to recognize these requirements. Therefore, I recommend that the requirements be reflected in the day-ahead market. This is best accomplished by making two changes to the protocols.

Q. What is the first change to the protocols that you recommend to reflect the local reliability requirements in the day-ahead market?

A. ERCOT should establish ancillary services market requirements so that the market results will reflect these local reliability requirements. Hence, the ancillary services markets would include market-wide ancillary services products, as well as locational products. When the locational requirements are not binding, the market-wide and locational prices for each reserve will be the same. However, when locational reserves are scarce, the locational price for the reserve can exceed the market-wide price for the same reserve. This provides an important economic signal to govern investment and maintenance decisions in the transmission-constrained area.

Q. What is the second change to the protocols that you recommend to reflect the local reliability requirements in the day-ahead market?

A. In addition to defining locational reserves, any physical commitment requirements to maintain reliability in local areas should be included in the day-ahead market commitment.

Q. Why is it beneficial for the day-ahead market to include zonal or other locational operating reserve requirements in its ancillary services markets?

A. Local operating-reserve requirements are very important because they are the only means to ensure that both the energy and ancillary services prices in the day-ahead market will reflect these requirements. This is critical because the need to build new generation is frequently related to the local needs of an area, i.e., because additional operating reserves are needed in the area to ensure reliability or because more resources are needed to manage congestion into the area. Accurately reflecting local reliability requirements as operating reserve requirements in the day-ahead and real-time markets would send efficient economic signals when conditions are tight or when resources are insufficient to meet the requirements. These economic signals serve two purposes. First, they provide appropriate incentives to build new resources that can help satisfy the local requirements. Second, they send efficient incentives to existing resources to maintain their resources and remain online, while avoiding excessive reliance on reliability must-run ("RMR") contracts.

Q. Do the nodal markets in the Northeast include locational operating reserve markets?

A. Not currently, although they are proposed in New England. The nodal markets in the Northeast have relied more heavily on their long-term capacity markets to reflect the need for generation in local areas. New York's existing capacity market includes locational requirements for New York City, while the proposed capacity markets in PJM and New England both include locational requirements.

Q. Could ERCOT following the same approach for addressing local capacity needs?

A. It could in theory. However, this approach is less accurate and actually infeasible absent a long-term capacity market. I understand that there are currently no plans in Texas to implement a long-term capacity market to ensure resource adequacy, but to rely instead on only signals from the energy and ancillary services markets to ensure adequate supply (i.e., an "energy-only" market). Therefore, it is essential that the local reliability needs be fully reflected in the energy and ancillary services markets, more so than in the nodal markets in the Northeast.

Q. Would establishing locational ancillary services markets ensure that enough resources would be committed in the local area in the day-ahead market?

A. No. Simply establishing locational operating reserve requirements may not cause the day-ahead market to commit sufficient resources in a local area. This is true for three reasons. First, it is not possible to translate all local needs into locational operating-reserve requirements. For example, certain voltage requirements can require that a specific unit be committed. Second, the day-ahead market may clear less than 100 percent of the net load in the local area (net of imports), so more physical resources are needed to be committed after the day-ahead market. Third, financial energy sales (i.e., "virtual supply") may serve some of the day-ahead load, requiring additional physical resources to be committed after the day-ahead market. These additional commitments will generally occur through the Reliability Unit Commitment ("RUC") process.

Q. Can you provide an example of how load scheduling and financial energy sales in the day-ahead market could result in the need to commit additional physical resources after the day-ahead market?

A. Yes. Consider a local area with a net load of 1000 MW (net of imports) and a local reserve requirement of 200 MW. If 900 MW of load is scheduled and100 MW of financial energy sales, then the day-ahead solution would commit 200 MW less physical capacity than is needed in the area. The day-ahead solution would include 800 MW of energy from physical resources and 100 MW of financial energy sales (900 MW total), plus 200 MW of local operating reserves on physical resources. Hence, 1000 MW of physical capacity would be committed in the day-ahead solution, short of the 1200 MW that is needed. For these reasons, additional resources would need to be committed to satisfy the physical capacity requirements in the local area.

Q. Why is it beneficial for the day-ahead market to include local commitment requirements?

A. Commitments through the RUC process made to manage congestion and meet other local reliability requirements raise efficiency concerns because they can lead to over-commitment of the system. When additional commitments are needed in a local area, it is frequently efficiency-enhancing to de-commit resources in other "unconstrained" areas. Failure to recognize this in the market design results in a less efficient commitment, distorted energy prices and ancillary services prices, and increased uplift. The New England independent system operator ("ISO"), for example, routinely commits quantities of resources equal to 5 to 10 percent of its peak daily load through its version of the RUC process.

Q. Briefly describe the unit commitment process that would need to be modified to implement your recommended changes.

A. One of the key components of the day-ahead market is a security-constrained unit commitment ("SCUC") model.[2] This model determines the unit commitment for the following day, given day-ahead energy demand, transmission constraints, physical constraints on the generating units, and ancillary services requirements. The unit commitment determinations include what units to commit and for what time periods. Since the commitment process involves starting a whole unit, it is computationally much more difficult than economic dispatch. Technically, this is referred to as a "mixed-integer linear program" since events, such as a unit commitment, are represented by an integer (i.e., 0 or 1). Other outcomes, like the generator dispatch, may smoothly vary. Unit commitment is determined over a planning horizon and broken down into intervals. Typically, the intervals are hours and the planning horizon is a day. Many parameters or constraints must be enforced over multiple intervals, such as generators' minimum run times or minimum-down times. These intertemporal constraints add significantly to the complexity of the commitment process.

Q. What changes would be needed to implement locational reserve requirements in the day-ahead market?

A. The current proposal in the protocols already envisages co-optimizing ancillary services ERCOT-wide. Therefore, a constraint would exist in the model requiring procurement of sufficient ancillary services for each interval ERCOT-wide. The only changes needed to implement my recommended locational ancillary services markets would be to add additional constraints to reflect the locational operating-reserve requirements. Adding a limited number of additional constraints in the context of the SCUC model used in the day-ahead market described above is a very minor software change.

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2 This model is distinct from the commitment model run in the RUC process, which is designed to ensure that all physical requirements can be satisfied the following day.

Q. What changes would be needed to implement the local commitment requirements?

A. Conceptually, this change is very similar to the changes needed to implement locational reserve requirements. The difference is that these local-commitment requirements are physical requirements to have sufficient generation in a local area that is either online or available from quick-starting resources, such as gas turbines. To ensure this, additional constraints would be included in the unit commitment model. These additional constraints differ from the locational-operating-reserve constraints in that they would be based exclusively on the physical resources and forecasted load in the local area. Financial energy transactions would play no role in satisfying these constraints.

Q. How should any uplift costs associated with satisfying these locational requirements be allocated?

A. I recommend that the uplift costs associated with commitments made to satisfy the local reliability requirements be allocated to all physical loads in the area protected by the commitments. These commitments are not simply economic commitments made to satisfy the demand in one market or another. Rather, they maintain the reliability of the local area, irregardless of whether the load in the local area purchased energy in the day-ahead or real-time market.

From an efficiency perspective, the important thing is that these costs not be allocated to real-time deviations from the day-ahead schedules (i.e., load that is not scheduled through the day-ahead market), which is the primary basis for the proposed allocation of RUC costs in the protocols. If it is allocated to real-time deviations, it may create significant disincentives for financial energy transactions and price-sensitive loads in the day-ahead market. The success of the energy-only resource adequacy mechanism under consideration at the Commission will depend in large part on the ability of commercial and industrial loads to respond to prices in the ERCOT day-ahead market. Hence, correcting the disincentives to price-sensitive loads in the protocols could significantly reduce the cost of meeting ERCOT's resource adequacy needs under a nodal market design. Both financial energy transactions and price sensitive loads in the day-ahead market can create significant real-time deviations. However, they are critical elements of the day-ahead market, ensuring that the day-ahead market results efficiently reflect expected real-time conditions.

Of less importance is how the costs are allocated geographically as this is largely an equity issue. However, given that loads settle on a zonal basis, it would be logical to allocate these costs by zone, rather than market-wide like local congestion costs are currently allocated. A zonal allocation would also reduce the incentive for participants that have load obligations and resources in the same area to withhold resources in order to inflate the uplift costs they would be paid (since they will bear a larger allocation of the costs).

Q. How would the protocols be affected by these changes?

A. A number of changes would be needed. First, the areas that address ancillary services markets would need to be expanded to include locational operating reserves. Second, the day-ahead market protocols would need to be modified to include additional constraints that would be solved as part of the day-ahead software as described below. Last, some of the RUC provisions would need to be applied to the day-ahead market. Most notably, the requirement that units be available to the RUC to meet ERCOT's reliability obligation should be extended to the day-ahead market for resources that are needed to meet the locational reliability requirements. These changes are reflected in the redlined protocols attached to this testimony as Attachment B.

Q. How would these changes affect market participants?

A. In the long-run, these changes will ensure adequate supplies in the local areas by providing efficient economic signals, which will ultimately benefit consumers in those areas and reduce ERCOT's reliance on must-run agreements and regulatory intervention. In addition, including the locational requirements in the day-ahead market will improve the efficiency of the commitment and should lower uplift costs. In the short-run, however, the locational operating-reserve requirements will likely increase energy and ancillary services prices in some zones because these changes will more fully price the reliability services provided by resources in certain local areas.

Q. Would implementing these recommendations increase nodal market implementation costs?

A. Implementation of these recommendations should not significantly increase the software costs. These recommendations involve applying additional constraints in the security-constrained unit commitment software. Such software is designed to find an optimal solution to a particular problem, subject to a variety of constraints (transmission constraints, generator constraints, etc.). Adding additional constraints should, therefore, not increase the development costs significantly for the day-ahead market software. Likewise, the cost-allocation changes should have a relatively small effect on the costs of the settlement software since it represents a relatively small change in the proposed allocation rules.

III. RELIABILITY UNIT COMMITMENT

A. Objective of the RUC

Q. What is the purpose of a Reliability Unit Commitment ("RUC")?

A. The protocols propose a reliability unit commitment process that is similar to the processes currently used by PJM, ISO New England, and the Midwest ISO. The

RUC is designed to meet two objectives – to ensure the committed resources are sufficient to meet forecasted loads and to maintain reliability in local areas. These commitments are generally made to minimize commitment costs (start-up and minimum-generation costs), which is appropriate. This process is not a re-commitment of the system with the aim of minimizing the cost of serving anticipated load. Therefore, the RUC should not decommit any units committed through the day-ahead market if it is conducted after the day-ahead market. Since the RUC is not performing a full economic commitment, allowing it to decommit resources would likely result in a very inefficient final commitment of resources. The protocols recognize this and prohibit decommitments, except to the extent that they are needed to manage congestion and meet reliability requirements.

B. Commitments Made by RUC

Q. Do the commitments made through the RUC to meet forecasted load raise any efficiency issues?

A. For the commitments made to satisfy ERCOT-wide forecasted load, the RUC process in the protocols raises limited issues. It would not tend to lead to an over-commitment of the system (because the units committed through the RUC are needed to meet load). It also should not substantially disturb the relationship between the day-ahead and real-time prices. If loads are substantially under-scheduled in the day-ahead market, prices will tend to be lower in the day-ahead market than the real-time market, providing an incentive for loads to increase their purchases or for participants to increase financial energy purchases to arbitrage the prices between the two markets.

Q. How should RUC costs associated with meeting forecasted load be allocated?

A. It is most efficient to allocate any uplift associated with commitments to meet forecasted load to the real-time purchases (load that was under-purchased in the day-ahead market).

This provides an additional incentive for load to be scheduled through the day-ahead market. Full participation in the day-ahead market promotes economic efficiency because it will improve the resulting commitment of generation and increases the opportunities for price-sensitive load to enter the market. The proposed allocation in the protocols is consistent with this recommendation, with the exception that the costs to be allocated are capped. The RUC shortage cap is two times the ratio of the QSE's capacity shortfall to the total capacity of all RUC-Committed Resources multiplied the by the total RUC Make-Whole Payments.

Q. Is it reasonable to limit the level of costs allocated to under-purchased load?

A. Yes. Because costs are being allocated only to the residual quantities of energy purchased in the real-time market, it is possible for a substantial cost to be allocated to an extremely small quantity. This can result in an unreasonable allocation. For example, suppose on a given day that one qualified scheduling entity ("QSE") is actually under-scheduled by 100 MW (the difference between the QSE's actual load and the amount scheduled day-ahead), while all other QSEs accurately scheduled their loads. Further, suppose that ERCOT forecasts a capacity shortage of 1000 MW and, therefore commits resources that result in uplift costs of $100,000. Without the proposed cap, the entire $100,000 would be allocated to the single participant even though it is only responsible for one-tenth of ERCOT's forecasted shortage.

Q. Is the cap the best means to prevent an unreasonably large allocation of the cost?

A. No. The problem with the cap is that it may continue to allow an unreasonably large allocation of the costs, for three reasons. First, the multiplier of two in the cap formula will allow allocation of costs significantly higher than the costs directly associated with the market participants' real-time capacity shortages. Second, if commitments are made for reasons other than meeting the market-wide capacity shortage, such costs would be allocated to the market participant described in my example above. Lastly, ERCOT will likely rely on off-line gas turbines to satisfy some of the shortfall between committed resources and forecasted load (because off-line gas turbines can provide capacity without incurring significant commitment costs). This can cause a larger than justifiable share to be allocated to the participant. In the example above, assume only 100 MW are committed in the RUC to meet the 1000 MW shortfall (i.e., ERCOT relies on 900 MW of off-line gas turbines, which can be dispatched after the RUC as needed). In this case, the protocols would allocate the entire RUC costs to the single participant.

Q. Do you have a recommendation for a better method of limiting inappropriate allocations of RUC costs?

A. Yes. An alternative provision that would address unjustifiably large allocations of the RUC cost to a QSE would be to allocate only the share of the RUC costs associated with meeting actual capacity shortages. Under this alternative allocation methodology, the QSE described in the example above would be responsible for the share of the uplift caused by its actual shortage – 10 percent of the total uplift costs (100 MW / 1000 MW) or $10,000. This provision is superior to the cap proposed in the protocols because the costs that will be allocated under this provision will correspond to the portion of the RUC commitments that are actually caused by the participant. In this way, the participant will receive a more efficient economic signal regarding its effect on the system of not serving its load through the day-ahead market.

Q. Would the revision to the protocols or the system development costs of implementing this provision be significant?

A. No. The protocol revisions would involve replacing the cap provision with an allocation provision based on the ratio described above. These revisions are shown in

Attachment B. The costs of this change should be small since the actual load of the QSE upon which the ratio is based is already needed by the settlement system.

Q. What recommendations do you have regarding the commitments made through the RUC to meet local requirements associated with transmission constraints, voltage issues, or other reliability needs?

A. As discussed in the previous section concerning the day-ahead market, I recommend that these local commitments be performed through the day-ahead market to the maximum extent possible. Making these commitments in the RUC raises significant efficiency concerns regarding the resulting generator commitments. In particular, it would tend to lead to over-commitment of the system since it would be inappropriate for the RUC process to de-commit resources in other areas. In addition, it places a heavy burden on the financial energy transactions and loads to reduce the net purchases in the day-ahead market in order to bring the day-ahead and real-time prices into convergence. Please refer to the day-ahead market section of my testimony for a more detailed discussion of why it is beneficial for these local commitments to be made through the day-ahead market.

C. "Clawback" Provisions

Q. Aside from the commitments made through the RUC process, do the protocols raise any other significant concerns?

A. Yes. I have concerns about the settlement provisions that would withhold some or all of the net market revenues in excess of a supplier's offer price (i.e., the "clawback" provisions).

Q. What is the intent of the clawback provisions?

A. The clawback provisions could have a significant effect on incentives for suppliers that have resources that are economic to commit. The intended effect of these provisions is to provide additional incentives for suppliers to make resources available in the day-ahead market, rather than waiting until the RUC to make resources available. However, I have two concerns regarding unintended consequences of the clawback provisions.

Q. What concerns do these provisions raise?

A. It is important to recognize that the clawback provisions affect only units that would otherwise earn positive net revenue (i.e., profit relative to their offer). With these provisions, these owners will now have an incentive to:

- Raise their offer prices. The clawback provisions create "pay-as-bid" incentives for the supplier because what they are paid is ultimately equal to (in the case of the 100 percent clawback) or closely related to their offer price. By raising its offer, a supplier would reduce the clawback and increase its revenue. It is very important to recognize that this is NOT an exercise of market power, but simply a response to the incentives created by the clawback provisions. Because competitive suppliers would tend to raise their offers, monitoring for potential abuses of market power would be more difficult (i.e., differentiating economic withholding from competitive conduct).
- Self-commit their resources. Suppliers that expect their units to be profitable at the real-time prices may self-commit their resources to avoid the clawback provisions.

Q. Are high levels of self-commitment bad?

A. Yes. High levels of self-commitment are harmful to market efficiency because self-commitment undermines the efficiency of the generator commitments and distorts the energy prices. One of the most significant benefits of the day-ahead market is the promise of an efficient commitment of generating resources. Suppliers have far less information than ERCOT on which to base commitment decisions. Hence, unless the generating resource is clearly economic, self-commitment can result in inefficient commitment patterns. If the quantity of self-commitments is substantial, this can contribute to an over-commitment of the system that will tend to depress real-time prices, resulting in lower net scheduling of energy in the day-ahead market and an attendant need to further arbitrage the prices in the two markets. This reduction in energy scheduled through the day-ahead market will tend to reinforce the need to rely on supplemental commitments after the day-ahead market. Lastly, the self-commitments are particularly harmful if they occur after the RUC because they can cause ERCOT to make unnecessary commitments in the RUC, leading to higher levels of over-commitment and inflated uplift costs.

Q. Do other markets that employ a RUC-type process have clawback provisions that are similar to those proposed in the protocols?

A. Not to my knowledge. ISO New England and the Midwest ISO do not have clawback provisions. I am not familiar with PJM’s settlement provisions. In none of these markets does the lack of a clawback provision contribute to excessive reliance on the RUC process or contribute to divergence between the day-ahead and real-time markets. The natural incentives provided by the day-ahead and real-time prices themselves promote relatively full participation in the day-ahead market.

Q. What is your recommendation regarding the clawback provisions?

A. I recommend the elimination of the clawback provisions. I have confidence in the incentives created by the day-ahead and real-time prices to promote full participation by both loads and suppliers in the day-ahead market. Some have argued that the lack of a mandatory offer requirement in the day-ahead market may make these provisions necessary. However, the Midwest ISO does not have a mandatory offer requirement, but nevertheless enjoys relatively full participation in the day-ahead market by both supply and demand.

Q. How would eliminating the clawback provisions affect the protocols and market development costs?

A. Deleting the clawback provision simplifies the settlements and should, therefore, slightly reduce the development costs for the nodal markets. Regarding the protocols, the primary changes needed would be to delete the provisions that define the clawback. The redlined protocols attached as Attachment B include these deletions.

Q. How would eliminating the clawback provisions affect market participants?

A. It should improve the operation of the day-ahead market and the efficiency of the generator commitments. Ultimately, this will improve the efficiency of the prices in the day-ahead and real-time market, and reduce uplift costs associated with RUC commitments.

IV. REAL-TIME MARKET

Q. What role does the real-time market play in the multi-settlement nodal electricity market?

A. The real-time market is essential because it provides a transparent economic basis for the results of the day-ahead market and the bilateral forward markets. The prices in the real-time market will govern what participants are willing to bid and offer in the day-ahead market and in forward energy markets. In particular, the bids and offers of the financial energy participants and physical participants ensure that the results of the day-ahead market will tend to converge with the real-time market. Therefore, it is critical that the prices in the real-time market be efficient and competitive.

A. Co-optimization of Reserves and Energy

Q. Does the basic structure of the proposed real-time market support the objective of achieving efficient real-time prices?

A. Yes. The nodal energy market will be a major improvement over the current zonal energy market. It should yield substantial efficiencies in the commitment and dispatch of generating resources, particularly when transmission constraints are binding. However, the dispatch could be further improved by following a similar procedure already proposed for the day-ahead market, which would be to optimize the resources that produce energy versus those relied on to provide operating reserves (i.e., co-optimization of energy and reserves).

Q. How do the protocols propose that ancillary services be procured?

A. The protocols call for day-ahead ancillary services markets that would be co-optimized with the day-ahead energy market. However, there is no proposed real-time ancillary services market, except in cases where ERCOT determines that additional reserves must be purchased. Hence, whatever resources are selected to provide reserves in the day-ahead market are set aside and unavailable in the real-time energy market, except under emergency conditions.

Q. Is the lack of a co-optimized real-time ancillary services market important?

A. Yes, it reduces the efficiency of both the reserves and energy markets by affecting where the reserves are held and the prices for reserves and energy.

Q. How does it affect where the operating reserves are held?

A. Many things can change between the day-ahead and real-time markets that would change the resources that are optimal to provide the operating reserves. For example, a constraint could bind in the real-time market that would cause a resource selected for reserves in the day-ahead market to be much more valuable to dispatch up to manage the congestion on the constraint. In this case, real-time co-optimization would shift the reserves from the resource in the constrained area to a resource outside of the constrained area.

Q. How does it affect the prices in the real-time market?

A. Anytime reserves are held inefficiently, prices will be distorted. In the example above, failure to reallocate the reserves from the constrained area to the unconstrained area would increase the nodal prices in the constrained area because the market would not be taking full advantage of all available resources to manage the congestion. In the real-time market, there will generally be a large quantity of very low-cost operating reserves in most hours. The marginal system cost of providing operating reserves from an online unit is primarily the suppliers' opportunity costs. Opportunity costs are incurred when economic resources (i.e., those for which it is cost-effective to produce energy) are dispatched down to provide the operating reserves and, therefore, profits are lost in the energy market. Opportunity costs are zero for any unit that is not dispatched at the top of its dispatchable range (e.g., a 500 MW steam unit running at 350 MW). Hence, these resources can provide reserves at a very low cost. In most hours when there is generally a large quantity of resources that are online, but not fully dispatched, these resources should be providing reserves, and the reserves prices should be very low to reflect their marginal costs of providing reserves, and the lowest-cost energy resources should be fully dispatched to provide energy (which will result in lower, more efficient energy prices). These results can only be assured by co-optimizing the operating reserves and energy markets in real-time.

Q. If ancillary services and energy are co-optimized in the real-time market, what would happen to the ancillary services providers selected in the day-ahead market?

A. The ancillary services providers selected in the day-ahead that are not selected in the real-time market would buy back the ancillary services they sold day-ahead, and would necessarily be better off. A day-ahead reserve provider that is dispatched for energy in real time would buy back its reserve obligation at the real-time reserve price and be paid the real-time energy price. To understand why the supplier would prefer this result, consider the following example.

- Suppose a supplier sold responsive reserves from a $50 per MWh unit in the day-ahead for $7 per MW per hour when the day-ahead energy price was $55 (his lost opportunity cost is $5). Hence, he would earn $7 per MWh of profit, $2 more than he would have earned providing energy.
- Now, suppose the responsive reserve price falls to $2 in real time and the energy price rises to $60. In a co-optimized market, he would buy back his reserve obligation at $2 and sell energy for $60. Therefore, his total profit would be: $10 from energy ($60-$50) plus $5 from reserves ($7-$2) for a total of $15 per MW per hour.
- Hence, the supplier's profit would more than double while consumers would benefit from allocating the lowest cost resources to provide energy and operating reserves.

Q. Do other markets co-optimize reserves and energy in real time?

A. Yes. The New York ISO has co-optimized its reserves and energy in the day-ahead market since the market began operation in 1999. However, it did not have a real-time reserve market until February 2005. Prior to that time, reserves were reallocated to other units in an optimal fashion, but payments were based on each resource's opportunity costs rather than a real-time clearing price for reserves. Although I am not an expert on the Australian market, I understand it is a single-settlement real-time market that is co-optimized under an energy-only resource adequacy framework.

Q. Please comment on the costs of modifying the market design to include real-time co-optimization of energy and operating reserves?

A. The incremental market design costs of real-time co-optimization of energy and reserves should not be significant, for two reasons. First, the software to perform the co-optimization will already be developed for the day-ahead market. The same optimization can be applied to the real-time market. Second, the changes needed are incremental and do not require the development of any additional new software components. To put these costs in context, the costs of New York's new real-time market was $32 million, which included substantial hardware, a new energy management system ("EMS"), a new supervisory control and data acquisition system ("SCADA"), and the real-time market software.[3] Although the costs of the market software are not separately identified by the New York ISO, they are likely a very small share of the total $32 million cost. Furthermore, most or all of the market development costs would have to be incurred with or without co-optimization.

Q. What protocol revisions are necessary to implement co-optimized energy and reserves markets?

A. I have attempted to modify the proposed protocols to reflect the changes that would be necessary to implement co-optimized real-time energy and reserves markets. These revisions are shown in Attachment B of my testimony. However, the necessary revisions to implement a new set of markets (real-time ancillary services markets) are extensive. Therefore, I strongly recommend if the Commission determines that the proposed nodal markets should be modified to include co-optimized real-time energy and reserves markets, that the Commission allow market participants and ERCOT to carefully review and identify any additional protocol revisions that would be necessary to implement these markets.

Q. What ancillary services would be co-optimized in real-time?

A. Only the operating reserves and energy should be co-optimized. Because it is likely necessary to identify which units are providing regulation services prior to the operating period, regulation should be scheduled prior to the operating hour. This

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[3] See New York ISO Press Release, February 1, 2005.

could be done in one of two ways. First, the regulating units scheduled in the day-ahead market could continue to be the providers of regulation services. Second, an hourly regulation market prior the operating hour could improve the allocation of regulation among units that are actually online. I would recommend the latter approach.

B. Pricing During Shortage Conditions

Q. When is the system in a shortage?

A. Shortages occur when energy and operating reserve demands cannot be met simultaneously. When this occurs, either load is curtailed or the operating reserves are compromised (i.e., the market software will not clear, so it must violate either the energy or operating reserve requirements). When this occurs, the marginal value of energy to the system is extremely high, which should be reflected in the energy prices and operating reserve prices.

Q. Are efficient prices during shortage conditions important?

A. Yes. They are extremely important, particularly in Texas if it chooses to rely entirely on the economic signals from the energy and ancillary services markets to maintain adequate resources over the long-run (i.e., an "energy-only" market). Other regions rely on capacity markets to supplement those signals. Even in those regions, justifiably high prices during shortage conditions play an important role in creating sufficient incentives for new investment and the maintenance of existing resources. In an energy-only market, as currently proposed by Staff for the ERCOT market and as compared to regions with capacity markets, spikes in energy and ancillary services market prices must be more severe and/or more frequent to create efficient incentives when capacity margins fall to minimum levels. Therefore, the long-term reliability of the ERCOT system requires that prices fully reflect any shortage conditions so that new investment (and maintenance of existing units) will occur in a timely manner when it is needed.

Q. Would the provisions in the protocols result in efficient prices during shortage conditions?

A. No, I do not believe they would. The primary means to achieve efficient prices in the protocols is for ERCOT to create a pseudo-resource that represents the aggregate capacity offered from those generation resources providing responsive reserve service.[4]

Q. Please describe the provisions associated with the pseudo-resource?

A. These provisions are designed to allow the system to become reserve deficient to a limited extent, while setting prices at levels exceeding the marginal production costs of most generating resources. The pseudo-resource would have a Low Sustainable Level (LSL) of 0 and High Sustainable Level (HSL) of 100 MW, with a ramp rate of 100 MW per minute. The protocols call for an offer curve to be created for this resource with an offer price of a minimum of $300 per MWh or 30 percent of the system-wide offer cap at 0 MW and a maximum of $1000 per MWh or 100 percent of the system-wide offer cap at 100 MW. If energy were dispatched from the pseudo-resource, the protocols indicate that the base points of the generating resources providing responsive reserve service would be modified in inverse proportion to their responsibility to provide reserves. I interpret this to mean that if 50 MW of the pseudo-resource is dispatched, the dispatch levels of each of the resources providing responsive reserves would increase in proportion to the reserves they are providing (which will convert 50 MW of responsive reserves into energy).

Q. Why will the proposed protocols not set prices efficiently during periods of shortage?

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[4] See the proposed nodal protocols, Attachment H, 6.5.7.3 (6).

A. The pseudo-resource provision is likely to be insufficient because the quantity is too small to adequately account for potential operating reserve shortages and it would not account for instances when costly measures are taken by the operators to avoid shortages.[5] In either of these two cases, each additional megawatt of energy supplied under these conditions would allow the system operator to hold an additional megawatt of operating reserves or to restore one megawatt of curtailed load. Under these conditions, additional energy is at least as valuable as the marginal value of the operating reserves or the curtailed load.[6] It is important that the market rules and software establish efficient prices when load is curtailed or operating reserve levels are decreased.

Q. What is needed to set efficient prices during shortage conditions?

A. I recommend that pricing provisions be developed to allow energy and reserve prices to reflect the costs of these reliability actions. To do this, the software must recognize two different things that occur during shortage conditions: a) load curtailments and other operator actions to prevent operating reserve deficiencies, and b) operating reserves deficiencies.

Q. How do you recommend that the nodal market be modified to account for load curtailments and other operator actions?

A. There are a number of different ways to recognize load curtailment and other operator actions in the market design. I encourage ERCOT and its software vendor to consider a full array of options. One way to do this is to model these actions as high-cost resources in the zone in which they are located. The protocols already propose a pseudo-resource to account for shortage conditions as described above. This

[5] I understand that the system operators in ERCOT may rely on load curtailments to maintain the full quantity of required reserves rather than allowing reserve levels to decrease.

[6] It would actually be worth more than the value of the foregone reserves, because an additional MW of energy would lower the system's production cost by the production cost of the marginal resource that would be backed down to provide an extra MW of reserves.

provision could be used to allow load curtailments to set prices by simultaneously incrementing the load and dispatching the pseudo-resource by the curtailment quantity. This would allow the price to be set by the offer of the pseudo-resource, which should reflect the value of the load that was curtailed. For example, if load is 59,000 MW and 500 MW of load was curtailed, the load would be increased by 500 MW in the curtailment zones for modeling purposes. If the pseudo-resource were needed to serve the load of 59,500 MW, it would set energy prices.

Q. How do you recommend that the nodal market be modified to account for operating reserve deficiencies?

A. The most straightforward means of ensuring efficient pricing during reserve deficiencies in a multi-settlement market where reserves are co-optimized with energy is to define an economic value for the operating reserves within the market model (sometimes called a penalty function). This economic value would be important during shortage conditions, because it would allow the model to choose to reduce its holdings of operating reserves when necessary to meet the energy demand (rather than simply not clearing). When the model makes this trade-off, the price in the energy market would reflect this value, as would the price in the reserves market. Some refer to this approach as defining a reserve demand curve, which was implemented by the New York ISO.

Q. Please explain the theory underlying demand curves for operating reserves in more detail.

A. The reserve demand curves ensure that the economic relationship between reserves and energy will be reflected in the market outcomes during shortage conditions. These reserve requirements are important market requirements in the sense that in non-shortage hours, the market models explicitly recognize the reserve requirements (i.e., the models are prevented from dispatching the operating reserves). When a market is in a shortage, it is generally the demand that will ration the supply and set prices. The relevant demand in this case is the demand for operating reserves. Hence, it is essential that the marginal value of the operating reserves be recognized by ERCOT when it optimizes and calculates prices for energy and operating reserves.

Q. What is the value of operating reserves and how is that value reflected in electricity markets?

A. Operating reserve requirements are an exogenous constraint established to protect the reliability of the system when contingencies occur, such as a generator or transmission facility going out-of-service (i.e., protecting against "loss of load"). The need to maintain operating reserves in order to meet the energy demand reliably stems from the fact that energy production in an electrical system must match the demand on a real-time basis. The operating reserve requirements are generally modeled in the ISO markets as "requirements" – constraints with very high or infinite economic values. In other words, the market models will incur any cost to satisfy the requirement. In reality, this is not consistent with operating requirements and practices. This is evidenced most clearly by the existence of an offer cap that establishes an implicit limit on the value attributed to operating reserves.

Q. How does an offer cap establish an implicit value for operating reserves?

A. To answer this, consider the $1,000 offer cap in the New York ISO as an example. The implicit value of reserves below this energy offer cap can be understood by examining what occurs during shortage conditions. When market conditions become tight, reserves are generally maintained by scheduling expensive energy, which allows the operator to reduce the output of a generating resource within the market to provide reserves to the system. The cost to the system of this action is the difference between the cost of the expensive energy and the incremental cost of the internal unit providing the reserve. For example, if a $1,000 per MWh import is accepted to create reserves on a $150 per MWh segment of an internal steam unit, the cost to the system is $850 per MW. This substitution will continue until the reserve requirement is satisfied or no additional substitution is physically possible. The $1,000 offer cap establishes a limit on the value of the reserves by restricting the ISO or RTO from accepting higher priced energy to make this substitution, which would result in higher system costs and, thus, a higher implied value of the reserves in question.

Q. Does the use of reserve demand curves mean that the Northamerican Electric Reliability Council ("NERC") reserve requirements would be violated?

A. No. Implementing reserve demand curves does not involve changes to, or a decision to ignore, NERC reserve requirements. On the contrary, the reserve demand curves can be designed to emulate the current operating requirements and reflect the implicit value of the operating reserves based largely on the offer caps that are ultimately implemented for the ERCOT nodal market. The reserve demand curves would provide increased consistency between the market outcomes and the operation of the system. Inconsistencies can lead to substantial distortions of the economic signals provided by both the energy markets and ancillary services markets. In other words, the market models are being modified to be more consistent with the operational requirements, not the reverse.

Q. Other than establishing efficient prices during shortage conditions, what other benefits do the operating reserve demand curves provide?

A. Inconsistencies between market software and the operation of the system can be evidenced by manual operator intervention. For example, in a market system with no perception of the relative value of different classes of reserves, the market may not efficiently convert lower-value reserves into higher-value reserves, which the system operator may do manually. For example, assume the shortage in the New York ISO example above is in 10-minute spinning reserves (the highest-value reserve). Further, assume that a substantial number of higher-cost gas turbines ("GTs") providing 10-minute total reserves are available (offer price = $300 per MWh). The market should convert these reserves to 10-minute spinning reserves by dispatching the GTs to provide energy (which generally must be operated at full output) and ramping down the $150 per MWh output range on the steam unit. If it makes this trade-off efficiently, the market will recognize the high-cost gas turbines as the marginal source of energy and set the price in the energy market at $300 per MWh. If the relative value of the reserves is not recognized by the market software, this trade-off would be made by the system operator as a manual action rather than by the software. The result is that the expensive turbines would appear to be dispatched out of merit, displacing the marginal output and artificially reducing the price in the energy market (to $150 per MWh in this case).

Q. Are significant software changes required to implement operating-reserve demand curves?

A. No. The market models must include some form of penalty function in the optimization that quantifies the economic penalty of violating a constraint (in this case, an operating-reserve constraint). Modifying this function to serve as a reserve demand curve is a minor change in the software that should not result in a significant increase in software development costs.

Q. Given that this is a mechanism that will result in high prices during shortage conditions, do these provisions enhance suppliers' market power?

A. No. These provisions do not create market power. A supplier that has the ability to create an artificial shortage can do so with or without these provisions. However, it does allow such a supplier to cause prices to rise sharply without increasing its offer prices by physically withholding its resource. It is very important that price spikes only occur during legitimate shortages, so the ability of suppliers with market power to physically withhold resources from the market must be effectively mitigated.

Q. How can physical withholding be effectively mitigated?

A. In the current zonal market, a large share of the available energy that could be produced by online units is not offered in the balancing energy market. Were this to occur in the nodal market, this shortage pricing approach could result in very high prices when the market is not in shortage. This can be addressed through mitigation by extending the energy offer of the unit to cover the withheld output of the unit. Alternatively, this capacity could be credited by the software as responsive reserves (to the extent that it can ramp within 10 minutes). Either approach would be equally effective in allowing the software to recognize that the system is not reserve deficient in real-time. This mitigation would not be effective for physical withholding in the form of forced outages or deratings falsely claimed by a supplier. This form of withholding can only be addressed *ex post* through a sanction that should be large enough to serve as an effective deterrent against such conduct.

Q. What do you recommend regarding physical withholding?

A. I recommend that the market monitor refer any instances of physical withholding that it detects to the Commission. The Commission should have sanctions or penalties that it can impose if it verifies the market monitor's finding that a participant physically withheld resources and raised prices. This recommendation does not involve any change to the protocols or development costs of the nodal market.

C. Dispatch and Pricing for Less Flexible Units

Q. What other pricing or dispatch issues are you concerned about based on your review of the protocols?

A. I am concerned about the dispatch and pricing of less flexible resources, which is a common issue that is confronted in developing efficient nodal energy markets. The protocols propose a five minute dispatch interval and a one hour reliability unit commitment. The five minute dispatch interval is relatively standard among nodal energy markets. However, this dispatch interval presents problems in dispatching and pricing gas turbines and other units that cannot be dispatched on a five-minute basis. The issues related to gas turbines are particularly important to address because they are generally the dominant source of supply over a specific marginal cost range.

Q. Please describe the nature of the problem?

A. Without provisions specifically addressing gas turbines, they would generally be dispatched manually by the operators or otherwise dispatched out-of-sequence with the five-minute market process (e.g., such as by the one-hour reliability unit commitment model). In either case, they are treated as must-take generation in the five-minute dispatch, essentially priced at zero. This will distort energy prices when they are the marginal source of supply by causing lower-cost dispatchable units to set the energy price.

Q. How can this issue be addressed?

A. I recommend the development of market software and supplemental processes together that would provide for the dispatch of gas turbines and the determination of efficient nodal energy prices under these conditions. These processes should satisfy two objectives.

Q. What is the first objective?

A. Gas turbines should generally only be started when they are economic (i.e., when the nodal prices justify their operation). Manual commitment of gas turbines can result in too many being started, and started too far in advance of when they are needed. These actions depress the nodal prices by forcing the energy from the gas turbines into the market. In general, gas turbines can start relatively quickly and provide the same reliability benefit (i.e., capacity) when they are offline as when they are online. However, operators may sometimes start gas turbines to convert non-spinning reserves into responsive reserves when responsive reserves are short. If the reserve demand curves and co-optimization provisions described above were implemented, this trade-off between non-spinning and responsive reserves would occur automatically.

Q. With the exception of committing gas turbines to create responsive reserves, how can the objective of committing gas turbines only when they are economic be accomplished with the 5-minute dispatch?

A. The market software should look ahead for an hour and indicate when a GT should be committed. This look-ahead feature is important for all resources because it allows the software to optimize its use of ramp capability on each of the resources. For example, a slow-ramping unit that will be economic in 30 minutes may be given instructions to begin ramping ahead of time so it will be producing at a high level when it is needed. Likewise, this forward-looking capability can be used to indicate when ERCOT should start gas turbines economically. This would prevent a surplus of gas turbines from being committed and distorting energy prices.

Q. What is the second objective?

A. The second objective is for gas turbines to set the nodal price when they are truly marginal.

Q. Why don't gas turbines normally set nodal prices when they operate?

A. Gas turbines frequently do not set energy prices when they are on the margin because they have a narrow operating range, which means they frequently run at close to maximum output and cannot be ramped down (i.e., their minimum generation level is close to their maximum generation level). When units operate at their minimum generation level, they are typically not eligible to set the energy price because they are constrained from moving down to their optimal dispatch level. This is reasonable for steam units, combined cycle units, or other units that are relatively flexible.

Q. Why is it reasonable for a gas turbine producing at its minimum generation level to set energy prices?

A. Gas turbines tend to be small and have relatively low start-up costs – and can therefore be considered a block energy offer. When their energy is needed to satisfy the market's energy and operating reserve requirements, the price should be equal to or higher than their offer prices. Even with the inflexibility of gas turbines, this issue would not be a problem if there were other flexible units online with similar costs to the gas turbines that could set the price when the gas turbines are needed. However, gas turbines tend to dominate the higher-cost portions of the supply curve in most markets such as ERCOT, resulting in situations where gas turbines are needed that have energy offers that are much higher than the "marginal" steam unit or combined-cycle generator (the generator whose output will change if load rises or falls by one megawatt).

Q. How can this second objective be achieved?

A. This objective requires software changes that would employ two parallel processes – one that would produce the physical dispatch that recognizes the inflexibility of the gas turbines, and one that would treat the gas turbines as being completely flexible with a minimum generation level of zero. With respect to the second process, in order to accurately determine whether the gas turbines are really needed, the ramp limitations for flexible steam units that are following dispatch instructions would be relaxed to allow them to ramp up significantly to replace the gas turbines. Hence, the second process would have the flexibility to reduce the output of the gas turbines and increase the output of the steam units for pricing purposes to determine whether the gas turbines are needed to serve load. This second process would set the nodal prices, but would not affect the physical dispatch of the resources. Hence, when a gas turbine is needed, the second process would indicate a non-zero dispatch level for the gas turbine and it would therefore be eligible to set prices.

Q. Are there any markets that employ this type of pricing approach?

A. Yes, the New York ISO implemented “hybrid pricing” logic that accomplishes this objective. It became necessary in New York because they rely heavily on gas turbines in eastern New York, particularly in New York City.

Q. Are there any settlement rules needed to accommodate this pricing approach?

A. Yes. The other units that are backed-down to make room for the block-loaded gas turbines would have to receive a supplemental payment reflecting their lost profits from not producing more energy. For example, if a $80 per MWh steam unit is backed down 100 MW to make room for some $140 per MWh gas turbines that set the price at its location, it would require a payment of $6000 to be made whole for that hour [100 MW * ($140 - $80)]. Without this payment, a steam unit that is backed-down would be harmed by being flexible, resulting in an incentive to the supplier to operate the unit inflexibly. For example, the supplier could increase its lower limit (i.e., its LSL) to compel ERCOT to dispatch the unit at a relatively high level. This inflexibility would be harmful to the market by preventing ERCOT from economically dispatching the system and managing congestion.

Q. If the New York market is the only one following your proposal, have there been alternative approaches in other markets to address your concern?

A. I am not aware of any other markets that have addressed this issue. Based on the early results in the Midwest ISO, as the market monitor for that market, I have identified this as a pricing issue that needs to be resolved. Gas turbines are frequently dispatched in the Midwest in intervals when they are needed, but are not setting energy prices.

Q. What is the negative consequence of not addressing your second objective?

A. The consequence of gas turbines failing to set prices when they are the marginal source of supply is that the real-time prices would be inefficiently reduced. This would naturally cause lower purchases in the day-ahead market (to arbitrage the day-ahead and real-time prices), resulting in fewer commitment through the market and more commitments through the RUC. Higher levels of RUC commitments generally translate to higher uplift and a less efficient overall commitment of resources. Furthermore, when gas turbines reliably set prices, they provide an important incentive for full participation by load in the day-ahead market in the following manner. Under-purchasing in the day-ahead leads to RUC commitments. The RUC should rely heavily on gas turbines due to their low commitment costs. Hence, it is likely that the gas turbines would run the following day to meet the day's peak energy demand. If they set prices at the marginal costs of a turbine, the real-time price would be significantly higher than the day-ahead price. This would provide the under-purchasing load a substantial incentive to increase the portion of their load scheduled through the day-ahead market.

Q. Are significant software enhancements needed to implement this change?

A. Yes. It requires a parallel software process that would not be needed, but for this change. However, it does not involve developing a new model. It involves running the same model with slightly different inputs in the two processes described above. Hence, the most significant change in the software involves developing the data processes to create two sets of inputs and to utilize the two sets of outputs from these processes. I estimate development costs of less than $3 million to implement these changes.

Q. Is this feature so important to the efficient functioning of the market that it is cost-justified?

A. Yes, I believe it is. Gas turbines are a very important segment of supply in any electricity market that must be capable of setting energy prices when they are on the margin. This will be particularly true in Texas if it ultimately relies on only energy and ancillary services markets to ensure reliable supplies over the long-term. Any flaws in the market that tend to dampen the energy price signals would threaten the development of adequate supply, harming Texas consumers over the long-run.

Q. **What protocol revisions are necessary to implement this process to allow gas turbines to be dispatched and set prices efficiently?**

A. I have attempted to modify the proposed protocols to reflect the changes that would be necessary to cause gas turbines to be efficiently dispatched and priced in the ERCOT market. These revisions are shown in Attachment B to this testimony. However, the necessary revisions to implement these changes are relatively extensive. Like my recommendation on the revisions necessary for co-optimizing real-time energy and reserves markets, therefore, I recommend that the Commission allow market participants and ERCOT to carefully review and identify any additional protocol revisions that would be necessary if the Commission orders these changes.

D. Market Power Mitigation

Q. What is your opinion regarding the focus of the market power mitigation measure proposed in the nodal protocols?

A. The market power mitigation whitepaper appropriately focuses primarily on local market power associated with network constraints. This is the most prevalent and severe form of market power in most electricity markets. In addition, the protocols do not establish a profit criterion for imposing mitigation. Although the ability to profit is a defining element of market power in the antitrust context, it is not possible to fully evaluate an electricity supplier’s incentives given limited information on the supplier’s financial positions and other arrangements. Knowledge of the suppliers’ physical positions and Congestion Revenue Right ("CRR") holdings does not provide sufficient information to draw reliable conclusions. Since it is not possible to accurately evaluate profitability, the appropriate focus for both monitoring and mitigation is on participants' conduct and the market effects of that conduct.

Q. The protocols call for the use of a multi-pass mitigation process that would utilize the results of the first pass (that includes only "competitive transmission constraints") to limit the offer prices in the second pass (that resolves all transmission constraints). What is your opinion regarding this approach?

A. I believe it is innovative and could potentially be effective in mitigating an array of market power abuses. However, I have some concerns that it may produce unintended results. Ideally, mitigation should only be imposed in the presence of substantial market power (presumably associated with the non-competitive constraints). However, the proposal appears to mitigate generators' offers even when no constraints are binding. The second security-constrained dispatch that determines nodal LMPs and dispatch levels (enforcing all competitive and non-competitive constraints) is conducted with mitigated offer curves. Until that run is complete, ERCOT would not know whether the non-competitive constraints would be binding. A third run of the dispatch model would appear to be necessary to mitigate only those units that affect non-competitive constraints.

Q. Can you provide an example that would clarify this concern?

A. Yes. Assume the first dispatch is conducted with only competitive constraints enforced and results in nodal prices of $40 per MWh in the North zone. The second dispatch would run with all units' offer prices reduced to the higher of $40 per MWh or their cost-based benchmark level. Assume that this run shows that only non-competitive constraints into Dallas-Fort Worth ("DFW") are binding. I would agree that mitigation may be warranted for the units in DFW. However, the second run may reflect substantial changes in dispatch levels outside of DFW where there are no market power concerns (e.g., units that had offered at $50 and not dispatched may now be dispatched when their offer prices are reduced to $40). Hence, this procedure would appear to be modifying offer prices in all hours, which is unnecessarily intrusive.

Q. What would be required to address this concern?

A. A third dispatch pass would be necessary to retain the mitigation of only the DFW units while releasing the mitigation of all other units. I had previously recommended that the Texas Nodal Team ("TNT") consider adding a third pass to this mitigation methodology. However, it may not be practical to run three passes within the five-minute dispatch interval.

Q. What is the negative consequence of not adding your proposed third dispatch?

A. As described above, the proposed mitigation approach would be extremely intrusive without a third pass to eliminate unjustified mitigation. Intrusive mitigation would inevitably constrain suppliers from submitting offers that must increase to reflect legitimate competitive factors (e.g., sharp fuel price changes, technical issues with a unit, opportunity costs, etc.). The rational response by a supplier in these cases is to use other means to avoid mitigation that would compel them to be dispatched at a loss, such as physically withholding the resource. Hence, it is essential not to impose mitigation that would routinely affect the conduct of participants that do not have or are not exercising market power.

Q. Do you have any other concerns regarding the real-time mitigation methodology?

A. Yes. I am concerned that the proposed real-time mitigation process could result in units being mitigated and unmitigated from interval to interval in a manner that would produce erratic dispatch signals. This can be addressed by retaining the mitigation for the balance of the hour once it is employed during the hour to reduce a resource's offer. This would increase the stability of the dispatch results. However, given the concern that this approach may be overly active in mitigating generators' offers (absent a third dispatch pass), retaining the mitigation for the balance of the hour may exacerbate distortions caused by this methodology.

Q. Are there alternative approaches to real-time mitigation that are likely to be superior to the approach proposed in the protocols?

A. Yes. One alternative to the proposed real-time mitigation measure that would address each of the concerns raised above is the "conduct-impact" mitigation framework applied in other nodal electricity markets.

Q. Under this framework, how would it be determined when mitigation should be imposed?

A. The mitigation measures employ a two-part conduct-impact test to determine whether mitigation is warranted. The test is designed to establish whether an exercise of market power would substantially distort market outcomes before mitigation would be imposed.

Q. What is the first part of the conduct-impact test for mitigation?

A. The first part of the two-part test screens the behavior of market participants to identify conduct that may warrant mitigation. Among other things, this "conduct test" identifies offers that exceed a competitive reference level by more than a defined threshold amount. The conduct test is key for differentiating between scarcity and market power for purposes of mitigation (i.e., if suppliers are not withholding physically or economically, any price increases are the result of scarcity rather than market power).

Q. What is the second part of the test for mitigation?

A. The second part of the test evaluates whether the market impact of behavior that violates the conduct test is significant enough to justify mitigation. The “impact test” accomplishes this by estimating the effect of the conduct on the relevant nodal prices and other specified market outcomes. Mitigation is only considered when these effects exceed clearly-defined thresholds. Using an impact test as one component of the trigger for mitigation is important, because conduct that does not have a significant effect on market outcomes is not, by definition, an abuse of market power and should not be mitigated. It is this test that causes the conduct and impact framework to mitigate much less frequently than the approach proposed in the protocols.

Q. **How would the competitive reference level be determined for a unit?**

A. To minimize the departure from the proposed protocols, ERCOT could use the same competitive references that would be used under the currently proposed mitigation approach – the higher of the generic production costs for the unit type or the verifiable unit-specific marginal cost. The latter should include opportunity costs and risks that would not be included in a participant’s out-of-pocket costs.

Q. Is this approach used elsewhere?

A. Yes. This approach is used reliably in the New York ISO, ISO New England, and Midwest ISO nodal markets. The primary difference in those markets is the means for establishing unit-specific reference levels. In those markets, the reference levels are primarily based on units’ past accepted offers during competitive periods. This approach has been effective and could be considered by the Commission as an enhancement to my primary recommendation. However it is not critical to use this “offer-based” methodology for establishing reference levels.

Q. How could this approach be applied in ERCOT?

A. Under this alternative, ERCOT would first run the model with all constraints enforced and no offers mitigated. The model would then be re-run in parallel outside of the production process (i.e., on a separate server) when a non-competitive constraint is binding with mitigated offers for the resources that are effective at relieving the non-competitive constraint. The model could also be re-run when one or more suppliers are pivotal in real time. If the mitigation significantly lowers the nodal prices in the second run, then the offers of the units that were tested for mitigation (those that failed the conduct test and affect the non-competitive constraint) would be replaced with mitigated offers in the next production interval and through to the end of the hour.

Q. Are significant software enhancements needed to implement this change?

A. Yes. Software would have to be developed to run the mitigation tests with a version of the market models running in parallel to the production market models. However, this is not more complex than the proposed multi-pass mitigation methodology proposed in the protocols. In fact, because the second run of the market model is performed offline, the development costs would likely be slightly less than the development costs for the approach proposed in the protocols.

Q. Does this approach require a more active market monitor?

A. No. This approach and the approach proposed in the current protocols are automated and do not require any actions by the market monitor. The only involvement of the market monitor is to maintain the competitive reference levels or benchmarks, and to monitor the process to ensure it is operating correctly. Both of the processes rely on competitive offer levels (default levels based on either unit type or unit-specific levels). Hence, the work needed to maintain this data is comparable under either approach. For example, a resource with relatively high marginal costs would need to provide information to the market monitor under either approach to ensure that it is not mitigated to levels below its costs.

Q. What changes in the protocols are necessary to implement this alternative?

A. Relatively extensive changes in the protocols are necessary to implement this alternative. Therefore, I have attached a modified version of the Midwest ISO tariff provisions that would be a useful starting point for a new protocol section that could be added. This new section is attached as Attachment C. Attachment B, my proposed redline of the protocols, reflects the deletions necessary to eliminate the multi-pass mitigation approach that I recommend be replaced.

Q. Are there any additional types of conduct that mitigation measures should be developed to address?

A. Yes. Mitigation measures should be developed to address manipulative financial energy transactions. In general, it should be difficult to significantly affect day-ahead prices by submitting financial energy transactions because other participants should have submitted bids and offers that would undermine these types of strategies. However, if the day-ahead market is not sufficiently liquid, particularly in the initial periods after implementation, there may be significant opportunities for manipulation. Such opportunities are increased if financial energy purchases and sales can be made at individual nodes rather than only at zones or hubs. For example, PJM and New England have both experienced issues with participants submitting financial energy trades that create sizable congestion in the day-ahead market that would not occur in real-time. This can be addressed by including a provision that would restrict the quantity and/or location of trades. Such restrictions should be imposed when participant's conduct has contributed to substantial divergence between day-ahead and real-time prices (including substantial differences in congestion patterns).

Q. What revisions in the protocols would be necessary to implement this type of mitigation measure?

A. Attachment D a revision of a measure from the Midwest ISO tariff. This provision could be appended to the protocols. One issue that would need to be resolved is whether such a restriction is imposed by the market monitor or the Commission. The market monitor could submit a referral to the Commission, who would be responsible for imposing the restriction. This is slightly different than the approach in Attachment D based on the Midwest ISO tariff, which provides the market monitor with the authority to impose the restriction.

Q. Do other RTOs employ this type of provision?

A. Yes. In addition to the Midwest ISO, a comparable provision is employed in New England and New York.

Q. What are the costs or other effects of this provision on participants?

A. There are no development costs associated with this provision since it is implemented as part of the overall market monitoring function. The effect of this provision would be to protect the integrity of the day-ahead market results and help ensure that manipulation can be quickly addressed.

Q. Does this conclude your testimony?

A. Yes.