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ACTIVITIES RELATED TO THE IMPLEMENTATION OF A NODAL MARKET FOR THE ELECTRIC RELIABILITY COUNCIL OF TEXAS	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

COMMITTEE OF CONCERNED LOADS' PROPOSAL FOR INCREMENTAL IMPROVEMENTS TO ERCOT's CURRENT ZONAL MARKET

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COMMITTEE OF CONCERNED LOADS' PROPOSAL FOR INCREMENTAL IMPROVEMENTS TO ERCOT's CURRENT ZONAL MARKET

INTRODUCTION

The Committee of Concerned Loads[1] ("COCL") offers the following comments and proposal to the Public Utility Commission of Texas ("PUC" or "Commission") for improvements to the existing zonal-based market. These improvements will enhance the effectiveness of actions taken by ERCOT both to dispatch the most efficient generation possible and to minimize congestion on the grid. These improvements will provide incentives to market participants to perform in a more responsible manner thereby improving the efficiency of ERCOT operations and reducing the total costs now uplifted to all Loads. COCL's proposal explicitly incorporates some of the 14 ERCOT market improvement recommendations of Dr. David Patton,[2] and while some of his recommendations are not specifically addressed, neither are they excluded from inclusion in further refinements of COCL's proposal. The development of the proposed nodal market will certainly provide no benefit to consumers. A new market design will not be necessary if the zonal improvements such as those presented in this document are adopted by the PUC.

Early implementation of an improved zonal market will provide a quick and cost effective solution to many of the problems identified with the current ERCOT market. This proposal will achieve many of the desired benefits identified in the Final Order under Project

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[1] The COCL is comprised of the following entities: The City of Dallas, the City of Garland, Denton Municipal Electric, the DFW Electric Consumer Coalition, Tara Energy, Inc., Gexa Energy, Cirro Energy, Cap Rock Energy, StarTex Energy, Texas Energy Association for Marketers, Utility Choice Electric, Greenville Electric Utility System, Public Power Pool, and Rayburn Country Electric Cooperative. (The members of the DFW Electric Consumer Coalition are: the City of Fort Worth, the City of Dallas, the Dallas Building Owners & Managers Association, the DFW Hospital Council, Texas Instruments, and 7-Eleven Corp.).

[2] David B. Patton, Ph.D., *2004 Assessment of the Operation of the ERCOT Wholesale Electricity Markets*, Presentation to ERCOT Market Participant Workshop, Dec. 10, 2004.

No. 26376, such as the reduction in local congestion costs, reduced opportunities for gaming and manipulation by market participants, and more efficient dispatch.

COCL believes it is important to note that the ERCOT Cost-Benefit Assessment[3] ("Study") currently under review by the Commission is a flawed comparison of two extremes, the yet-to-mature existing zonal-based market and a not-yet-fully-designed nodal-based scheme. As was discussed at the PUC Technical Conference held on February 10, 2005, the pricing of the Study's Base Case model does not in any way reflect the appropriate energy prices for the zonal market settlement or the price incentives for siting new generation. With such a significant flaw in the underlying information, the Study cannot be used in its current form as a credible basis in determining how to move forward.

A third choice exists that was not evaluated in the Study, namely, the costs and benefits of a set of specific and directed improvements to the existing zonal-based market that would produce quick and cost effective results. The Backcast portion of the Study does not attempt to capture market pricing strategy, market power issues, bilateral trades, and transmission outages, among other things, and is therefore of no use for reflecting on the efficiency or the lack of efficiency of the zonal model in 2003. However, even if one were to accept the credibility of Tabors-Caramanis Associates' "non-comparison"[4] of "optimal" zonal results with the actual zonal results, then to be intellectually honest one must also acknowledge the potential for $1.1 billion savings (a 14% cost reduction)[5] per year available from optimizing the existing market as

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[3] Tabors-Caramanis & Associates and KEMA Consulting, Inc., *Market Restructuring Cost-Benefit Analysis, Final Report*, Electric Reliability Council of Texas, Nov. 30, 2004.

[4] *Ibid.* p. 4-1, TCA says, "The Backcast analysis is not a comparison of the existing Base Case with the Nodal Case. Rather it is a comparison of simulated generation with actual generation."

[5] *Ibid.* p. 4-3, Tables 4-1 and 4-2. (In Table 4-2, the ERCOT line, third column, shows a reduction in Generation Cost for an "optimized" zonal model of $1.132 billion. This amounts to a 14% reduction from the Actual Generation Dispatch shown in Table 4-1, the ERCOT line, third column, of $8.1 billion.)

identified in the Backcast portion of the Study, in the near term, as opposed to a $76 million (a 0.57% cost reduction)[6] per year savings opportunity from switching from a zonal to a nodal market.

1. CURRENT PROBLEMS

The most serious problems with the existing ERCOT market require solutions that do the following:

i) Reduce the costs uplifted to all Loads,

ii) Assign controllable costs to the appropriate entity or entities whose actions are responsible for the costs, and

iii) Enable and empower ERCOT to more efficiently manage operation of the grid.

Some market participants might also identify other items. However, a proposal that accomplishes these goals of reducing uplift, appropriately assigning the uplifted costs to those who cause it, and empowering ERCOT to improve the efficiency of its dispatch, will produce significant benefits beyond those available from current operations. If the plan also reduces the time, cost, and potential legal and political risks associated with a complete redesign of the ERCOT market, then it will have even greater value.

2. DESIRED OUTCOMES

The value of any solution to the problems of an already known quantity, such as the existing ERCOT market structure, increases with the ability to implement it within the framework of that structure. Working within the current structure will allow for the quickest improvements to the Texas electric market. It will not require rewriting and relearning Protocols in their entirety or designing, purchasing, installing and testing new systems, and it will result in

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6 *Ibid.* p. 3-22, Table 3-4, (Arithmetic average of the reduction in generation costs over the 10-year period shown in the last column of table).

fewer unforeseen problems. Many unanticipated problems with the current market have already been worked out over the past three plus years, so in many ways it would be taking several large steps backwards to totally redesign the market now. A complete market redesign will have many unpredictable consequences. But improving the current market design significantly reduces the financial burden on market participants, particularly the small entities who will be disproportionately impacted and who will still be required to pay for and to implement a complete market redesign. The smaller entities, including consumers, do not have the resources of the other market participants to be adequately heard in this process, and their pleas to improve zonal operations have been all but ignored to date.

The value of improving the existing zonal market increases significantly due to the ability to implement a solution within a much shorter time frame than that which could be achieved in a change to a nodal design. Due to the time value of money, everything else being constant, the net present value of savings achieved under an improved zonal market is higher than those savings obtainable under a nodal design because they can be achieved much sooner. In fact, everything else is not constant. The costs and risks to implement an improved zonal market are much less than the contemplated change to a nodal market design. The immediate reduction in uplift (*i.e.*, costs) to Loads, the ability to assign costs to those who cause them, and the improved efficiency in ERCOT dispatch are problems of such magnitude today that the value of their immediate resolution dwarfs the nebulous and indeterminate value of a complete market redesign that cannot be implemented for several years and which will create even greater problems of its own.

The value of any solution to the problems in the existing ERCOT market increases with the degree in which the solution recognizes that the ERCOT market is now, and ever will be, deficient in one or more of the prerequisites for pure competition. "The Theory of the Second-Best", formalized by economists Lipsey and Lancaster[7], warns that externalities such as transmission limitations, fuel and emissions limitations, localized market power and other such problems prohibit any system from being able to guarantee complete economic efficiency. It must also be recognized that those with regulatory authority over the conduct of market participants will have to act on a regular basis to correct the detrimental effects caused by these externalities, and to create a structure in which the role of the regulatory agency is authoritative, swift and effective. Opportunities do exist to improve regulatory oversight over ERCOT's zonal market.

COCL recognizes that there may be some additional costs incurred by ERCOT to improve zonal operations. However, most of the additional costs will include improvements and "fixes" that should have been already completed to set up the proper zonal structure that was originally envisioned. Much precious time and many resources have been devoted to a nodal design which should have been directed towards improving what already exists.

What the market participants, including consumers, need is a solution that can be implemented within the existing market structure that is less expensive and less uncertain in its potential outcomes. It must simplify the identification of inappropriate and detrimental behavior so that regulatory intervention may be swift and effective. Furthermore, the proposed solution must reduce uplift to Loads, assign more costs to those who act to increase them, and facilitate more effective dispatch by ERCOT.

This proposal addresses all these issues.

3. PROPOSED CHANGES TO THE EXISTING ZONAL MARKET

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7 R.G. Lipsey and R. K. Lancaster, *The General Theory of Second-Best*, 3 Rev. Econ. Study 11 (1956).

There are six principle areas of improvements that can be made to the existing zonal market to produce the desired outcomes. They are as follows:

1. Bus Level Dispatch
2. Enforcement of SCE Obligations
3. Allocation of Ancillary Service Costs
4. Zonal Replacement Reserve Service Market
5. Cost-Based Payment to OOM Units
6. Improved ERCOT Dispatch

a. Bus Level Dispatch

The first proposed change is to declare that no Qualified Scheduling Entity ("QSE") will represent any more generation than the units connected to a common bus at a plant site. The output of any unit in such a portfolio would be electrically indistinguishable from the rest of that portfolio. This will eliminate the operational problems caused when ERCOT directs the portfolio of a QSE to increase or decrease output and must then issue countermanding unit-specific orders because the initial change in output occurred at a different plant than ERCOT expected.

By limiting the portfolio to the capacity of the units on a single bus, ERCOT can insure that Balancing Energy[8] awards are made with sufficient precision to greatly reduce the amount of unit-specific up and down orders that are now used to force the change of output for large portfolio QSEs. This will cause the generation change to effectively appear at the location where it is needed. The PUC could force divestiture of units to create such an environment. However, COCL proposes that ERCOT merely require a QSE to form a sub-QSE for all resources at a

[8] Balancing Energy is energy that is deployed in intervals by ERCOT when scheduled generation varies from short term forecasts of actual load.

single bus and require that bid, award, and settlement be made at the sub-QSE level. With this approach, ERCOT can operate as it does today, but in a more effective way, and without the need to make substantial changes to its existing software.

Furthermore, ERCOT should not award Balancing Energy to a sub-QSE when to do so would create a congestion situation requiring additional Out of Order Merit ("OOM")[9] orders to compensate. This can be accomplished now in ERCOT's Energy Management and Monitoring System, Release 3, so this is not a major technical change; however, some have complained about this feature as it sometimes raises the Market Clearing Price for Energy ("MCPE") when the ERCOT system has to go deeper into the bid stack to replace the output of the skipped units. It should be noted here that a higher MCPE only affects those who are, and should be, price takers in the balancing market, while uplifted OOM payments are allocated to all Loads.

These are straightforward changes requiring possibly a larger database at ERCOT to accommodate hundreds of sub-QSEs, and requiring revised bidding practices by QSEs now representing units on multiple buses. The costs of these changes are much less than the costs of conversion to a nodal system and can be implemented much earlier. The use of bus specific dispatch instructions would provide ERCOT better tools in managing the actual impact of generators and the ability to choose the least cost combination to control the immediate system needs. This would reduce the amount of both inter-zonal and intra-zonal congestion costs because a light will shine into the black portfolio bid box.

ERCOT is currently investigating the cost to implement additional sub-QSEs as requested in Protocol Revision Request ("PRR") 555. More precise costs should be available

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[9] Out of Order Merit ("OOM") dispatching is when ERCOT dispatches individual generator outputs up and down in order to alleviate transmission operational problems without regard to the bid position of that generator in the economic order of dispatch.

from ERCOT soon. At any rate, the cost to implement additional sub-QSEs will be considerably less than implementing a new market design.

b. Enforcement of SCE Obligations

It is time to recognize that in an interconnection the size of ERCOT, the poor performance of any entity creating Schedule Control Error ("SCE")[10] forces other entities to compensate for that egregious behavior and to subsidize that entity. Precise planning by ERCOT and the precise awarding of Balancing Energy to minimize resultant generator unit re-dispatch (*i.e.*, OOM) is of little value if a QSE simply generates what it wishes rather than what it is obligated to produce. It should also be recognized that the obligation components of a generation schedule are undertaken voluntarily, but once undertaken they do become an obligation. A generator or QSE simply should not commit to schedules that it cannot or will not perform.

ERCOT will never become efficient in controlling frequency and will never become adept at responding to unintentional disturbances so long as it effectively remains permissible to treat schedules as a suggestion. Failure to follow generation schedules in an interconnection as small as ERCOT continues to cause ERCOT to require superfluous quantities of Ancillary Service[11] capacity. While the costs of providing these Ancillary Services are the obligation of Loads, the allocation of this obligation is made by Load ratio share, which causes Ancillary Service costs actually to be just another form of uplift.

To put the issue of uplifted OOM charges for capacity and energy in context with the other uplifted costs, one must recognize that these costs, which are normally associated with

[10] Schedule Control Error is the difference in any given time interval(s) between a QSE's obligated generation and its actual generation. To the extent that there is a difference between the two values, system frequency is affected and ERCOT deploys Ancillary Services to reduce the error.

[11] Ancillary Services are various arrangements between ERCOT and generators (or loads) for the purpose of balancing loads and resources throughout the day in order to keep system frequency within the nominal limits.

intra-zonal congestion, currently total approximately $200 million per year. This is slightly more than the annual amount uplifted to Loads in the form of the ERCOT Administration Fee, and less than one-half of the annual amount uplifted to Loads in the form of Reliability Must Run ("RMR")[12] Reserve Service. Ancillary Services are actually another form of uplift to Loads and their total burden is in the neighborhood of $400 million per year. Obviously, OOM charges are an important issue, but they are an important issue only because they are a piece of a much larger equation. The entire equation needs to be evaluated separately and holistically. This issue cannot be analyzed in isolation.

Conformance to SCE requirements is a straightforward and fair parameter to enforce. While there are many reasons why a QSE might want to either schedule energy and services that it cannot provide or choose to refuse to minimize its SCE, its incentives are likely to be perverse if it knows it can shift the cost of not performing its obligations to the payers of Ancillary Services. Valid short-term reasons for temporary SCE non-performance exist, such as the unplanned outage or forced runback (*i.e.* a forced reduction in output) of a generating unit. But there is no valid excuse for regular and continuing violations of schedule obligations. These repeated violations should subject the perpetrators to penalties sufficient in size that they are forced to alter their behavior.

The improvement to zonal operations recommended herein primarily requires the Market Oversight Division of the PUC ("MOD") to require the creation of, and the will to enforce, ERCOT Protocol revisions that make repeated non-compliance with good SCE performance an action subject to enforcement proceedings. This change requires no significant system changes by ERCOT, but does require the discipline of market participants to coordinate their marketing

[12] RMR is a service for capacity and energy that is contracted between a generator and ERCOT. The contract is put in place because the generator, which is needed to maintain reliability in a transmission restricted area, would be uneconomical to run, but for the contract.

desires with the physical capability of its generators. These changes will not burden those that meet SCE requirements. The benefits will be improved system control by ERCOT, and because the need for Ancillary Services will be reduced, the costs uplifted to Loads will also come down.

c. Allocation of Ancillary Service Costs

It is interesting to recall that ERCOT stated shortly before the opening of the current market that it would need 600 MW of Regulation-up and 600 MW of Regulation-down.[13] However, the requirements were actually doubled during the first month of the new market operations as a precaution against the unknown effects of the new system operation. Three years later, not only are the regulation requirements still at the 1200 MW level, but ERCOT recently proposed doubling them again during certain hours when non-compliance with SCE requirements by many generators and QSEs regularly causes severe frequency disturbances.

Compliance with SCE requirements must be enforced. The need for most of the 1200 MW Regulation-up and Regulation-down resources is due to lax SCE performance. The desired outcomes of reducing uplift to Loads and allocating costs to causation will occur only if an environment is created in which entities have sufficient economic incentive to compete with each other to minimize SCE to the maximum extent practicable.

A mechanism was introduced over two years ago in PRR 356, which proposed that the costs of providing ERCOT with Ancillary Services should be borne by QSEs proportionately to their SCE. Any similar mechanism that automatically rewards good SCE performance and burdens poor performers would effectively create economic incentives to bid and schedule

[13] Regulation-Up is on line generation that automatically increases its output to prevent system frequency from sagging below its limits when system load exceeds system generation. Regulation-Down is on line generation that automatically decreases its output to prevent system frequency from rising above its limits when system generation exceeds system load.

responsibly. The self-mitigating nature of a mechanism such as that proposed under PRR356 would accomplish all this without requiring significant additional efforts by the MOD.

This proposed change, *i.e.*, to enforce SCE obligations, would require certain minor alterations to the ERCOT settlement process, changes that were determined to be feasible two years ago when PRR 356 was introduced. Costs of implementation by ERCOT would be quite small, while the costs to those not willing to minimize their SCE could be substantial until they elect to perform. The benefits include improved system control by ERCOT and the shifting of Ancillary Service costs from Loads to those whose behavior increases the need for Ancillary Services.

It should be noted that the regular deployment of Ancillary Services in ERCOT, not in response to any genuine emergency, but in response to the operating practices of a few entities with large SCE, does present a serious reliability risk to the ERCOT interconnection. If Ancillary Service reserves are already fully deployed at a time when ERCOT must take action to compensate for the willful actions of entities with large SCE, then there will be nothing left with which to respond to a *bona fide* emergency. Such a scenario is fraught with firm-load shedding implications.

d. Zonal Replacement Reserve Service Market

It is reasonable to require QSEs in any ERCOT Load Zone to have sufficient online capability to meet the Load obligations projected for that zone less the post-contingency ability to import energy into that zone. This is the reason the current market intended to have a Replacement Reserve Service[14] market. Unfortunately, ERCOT has not been able to effectively run a Replacement Reserve Services market to date.

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[14] Replacement Reserve Service is a resource procured by ERCOT via a bid process for use during certain periods of time when ERCOT determines that scheduled resources do not appear adequate to meet forecasted load.

The lack of a Replacement Reserve Service market has allowed entities to under schedule Load and thereby under schedule generation, which in turn forces ERCOT on occasion to commit additional units (via OOM procedures) and uplift the cost to Loads. If ERCOT were to acquire the additional needed capacity via a Replacement Reserve Service market and allocate the costs of committing these units to those who were actually resource deficient, then a QSE would be incentivized to bring on line adequate resources at its own cost and initiative. Every unit brought on line in an effort to avoid paying for replacement power will reduce uplift. The cost of every unit brought on via a Replacement Reserve Service market can potentially be assigned to those who were short in the market.

ERCOT currently advises that it may be able to begin to run a daily Replacement Reserve Service market later in 2005 pending the implementation of announced software upgrades. A mechanism for assigning Replacement Reserve Service costs to entities that are short was developed during discussions on Relaxed Balanced Schedules ("RBS")[15] among ERCOT market participants over two years ago. Implementation of this change should be neither difficult nor time consuming. The primary benefits of operating a Replacement Reserve Service market is that it creates an incentive for QSEs to make zonally balanced unit commitments, plus it provides potentially significant reductions in OOM costs that are now uplifted to Loads. Rather than rushing to implement a new market model, it would be more cost-efficient to allow ERCOT time to implement this upgrade and to conduct such a Replacement Reserve Service market that would charge the entities for the full impact of their being short of resources.

[15] Relaxed Balancing Schedules allow a QSE to take more of its energy from ERCOT's Balancing Energy Market instead of scheduling the supply from one of the QSE's own resources.

e. Cost-Based Payment to OOM Units

Over the last twenty-five years, many *integrated resource planning* solutions have been implemented to solve the problem of reliably serving all Loads in ERCOT all of the time. For some of those solutions building additional transmission solved the problems and in other cases installing well-sited, new generation did the job. In the majority of situations, entities followed PUC-approved *integrated resource plans* to cost-effectively solve this problem of balancing the need for more generation vs. more transmission. Integrated transmission and resource planning can still be effective and should remain the goal of the PUC and ERCOT.

Constructing new transmission in ERCOT increases net Transmission Cost of Service ("TCOS") payments for all Loads. Transmission that is not built because generation was a cheaper solution does not increase net TCOS payments for all Loads, but may ultimately result in additional uplift. All Loads are now paying higher uplift costs because uneconomic generators are forced to run in areas where needed transmission was not built. While this may be unfortunate from some perspectives, it is hardly unfair to unconstrained areas given the *integrated planning* approach in years past that resulted in fully vetted plans to solve some local problems with transmission and others with generation.

What is unfair is that it is now possible for some generators to capitalize on this lack of transmission in certain areas, while other generators are forced to operate at a loss. Compensation to any unit subject to OOMC or OOME dispatch should be sufficient to cover actual, verifiable expenses of complying with such orders, but no more.

Entities ordered by ERCOT to take actions against the economic interests of their own customers should not be made to suffer; otherwise incentives are created for them not to respond to grid security needs.[16] Entities that could elect to make needed capacity available for deployment but choose not to do so because OOM payments are more lucrative, will be an uplift burden to all Loads. It is recognized that paying for OOM services at cost may drive some units into requesting RMR Service. However, an RMR contract does require an exit strategy, and thereby a path exists to ultimately end those costs.

It will not be straightforward for entities to compile cost data that enables routine determination of actual generation costs, nor will it be straightforward for ERCOT or MOD to verify, approve, and periodically review these costs. However, a 2% reduction in congestion costs is worth about $4 million per year, an amount that would easily fund these efforts at ERCOT or MOD.

The benefits of this change to a cost-based payment approach for OOM deployments will be reduced uplift to Loads and a heightened awareness to generators when siting new units.

f. Improved ERCOT Dispatch

The record is replete with examples of ERCOT's having to dispatch hundreds of megawatts of remote generation in order to cause a one or two megawatt post-contingency overload improvement in a line. ERCOT should be permitted to act more sensibly to reduce these uplifted costs.

ERCOT staff addressed this issue very well on October 21, 2004. Joel Mickey delivered a presentation titled "BES Deployment and Zonal Average Shift Factor."[17] In that report, he

[16] For instance, suppose that a QSE that is satisfactorily serving its load is told by ERCOT that a system security issue exists on the transmission system such that the QSE must back down its generation by 100 MW. The QSE is still responsible for meeting its load so now it acquires new resources from the system at MCPE. If the MCPE is $20/MWH higher than the price of the resource that was backed down, then the QSE has lost $2,000 per hour (100 MW x $20/MWH = $2,000/HR.) The QSE should be compensated for the loss it incurs from taking this action as directed by ERCOT.

[17] Joel Mickey, *BES Deployment and Zonal Average Shift Factor*, ERCOT PowerPoint Presentation, October 21, 2004.

used, as an example of the problem, events during the interval ending at 13:00 on June 9, 2004. In that interval there was inter-zonal congestion from South to Houston. The transfer limit from South to Houston was 950 MW; the actual flow was 992 MW, an overload of 42 MW. Acting under the current operating procedures, ERCOT issued 2868 MW of Up-Balancing Energy Services ("UBES") instructions to one group of generators and 1858 MW of Down-Balancing Energy Services ("DBES") instructions to another group.

The information on slide 5 of the presentation shows that in order to correct the actual transmission overload of 42 MW on that day, ERCOT issued the following instructions:

1. Increase generation by 919 MW in the Houston Zone,
2. Increase generation by 1834 MW in the North Zone,
3. Decrease generation by 1220 MW in the Northeast Zone,
4. Increase generation by 115 MW in part of the South Zone,
5. Decrease generation by 430 MW in another part of the South Zone, and
6. Decrease generation by 208 MW in the West Zone.

The frustration among ERCOT staff is apparent in Mr. Mickey's comment on this bumbling redispatching process when he says in the subsequent slide 6, "Is this what we want?" The total instructions to increase generation amounted to 2,868 MW and the total instructions to decrease generation totaled 1,858 MW. 4,726 megawatts of generation was redispatched to solve a 42-megawatt problem!

The presentation goes on further to say that one of the significant reasons for this type of movement of generation resources is the use of zonal average shift factors[18] that are not

[18] Shift factors are estimates of how much power flows over a given line or a set of lines given a specific set of power injection and removal points. For example, if 100 MW is injected into bus A in south Texas and 100 MW of generation is backed down (i.e., removed) at bus B in north Texas (thereby keeping the system balanced), then the amount of power that flows through every line or every designated set of lines in ERCOT divided by 100

representative of the actual impact of that dispatch. ERCOT issues instructions based upon those average shift factors and with the portfolio method the QSE can move any generator within its portfolio in that zone. The initial redispatch of some generation resources causes unintended line loadings which further require the redispatch of additional units to counter the detrimental aspects of the first redispatch and so on and so on. This occurs because there may be units within a zone that actually have negative and positive shift factors whose effects are masked under the zonal constraint averaging.[19] The QSE makes the choice of which unit to move regardless of the actual shift factor of that unit. As illustrated above, this may cause additional remedial instructions from ERCOT to correct the impact of those units actually dispatched. Under the COCL proposal, this problem is resolved through bus level dispatch instructions allowing ERCOT to operate and manage the transmission system in a more cost effective manner.

If bringing a unit on or taking a unit off ("OOMC[20]") is a cheaper alternative than raising or lowering the output of an already-running generator ("OOME"[21]) that has a ridiculously low shift factor, then ERCOT should be permitted to make the cheaper choice, *i.e.*, OOMC. If the switching of other transmission lines eliminates the need for a solution using expensive generation changes, then ERCOT should be permitted to make the less expensive choice and

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MW is defined as the transaction's "shift factor" for that line or set of lines. If, as a result of the 100 MW transaction, 20 megawatts of additional power flows through a transmission line in Houston, then that line has a shift factor of 0.20 (20 MW/100 MW). If the 20 MW of additional line loading results in the line being overloaded by 10 MW, then by reducing the transaction from 100 MW to 50 MW, the overloaded line's flow will drop by 10 MW (50 MW x 0.20) and its limit will not be exceeded.

[19] A positive shift factor is when the transaction increases flows on the line and a negative shift factor is when the transaction decreases the flows on the line.

[20] OOMC is Out of Order Merit Capacity. It is when generator units, and their "capacity," are brought on-line or taken off-line in order to solve an ERCOT problem.

[21] OOME is Out of Order Merit Energy. This occurs when already-running generators have their outputs ("energy") increased or decreased in order to solve an ERCOT problem such as caused by limitations on the transmission system.

switch a line. Recurring situations with straightforward transmission solutions must be identified and the implementation of the solutions must be encouraged. Former utility control areas were responsible for solving problems at least-cost to their end-use customers. ERCOT must be permitted to do the same and it must be enabled and empowered to act for the good of all Loads.

ERCOT is required to follow approved operating Protocols and usually does not have the discretion to take a less expensive solution. However, rote duplication of actions taken last year just because a computer sets off an alarm today is not always good. Unexamined actions can indeed unnecessarily increase uplift costs and decrease system reliability. ERCOT Operations has full authority under the Protocols to preserve system reliability; with that authority it must be free to act in a measured and reasonable manner. In any event, it is not a prerequisite that the entire market be redesigned in order for ERCOT to dispatch in a more cost-sensible manner. Cost savings from more efficient dispatch can be achieved today without the time and expense needed to created a new nodal-based market.

4. WHAT DOES NOT CHANGE

The discussion so far has focused on a proposed set of improvements to the existing zonal-based market. These are changes that can be easily and quickly implemented to give early and substantial cost relief to Loads, and these changes will result in a more disciplined and secure market. If the changes recommended by COCL are implemented, the basic framework of the current market could continue for some time. However, some things will not change.

Existing CSC-based[22] Load Zones will continue. This means inter-zonal congestion, Pre-Assigned Congestion Rights ("PCR") awards, and Transmission Congestion Rights ("TCR") auctions will continue in the existing manner. Potential economic devastation that would fall

[22] CSCs are the Commercially Significant Constraints that exist between each ERCOT Load Zones. These can be thought of as estimates of the power flow limitations between the Load Zones.

upon some Loads as a result of proposed nodal methodologies would be avoided, as would harm that could impact the entire Texas economy and would certainly spawn any number of legal actions.

The direct link between Loads and the Resources they select will continue. No Load will be exposed to a zonal MCPE except to the extent it chooses and to the extent Resources do not perform.

ERCOT will still have fundamental hardware/software and instrumentation problems. It will continue to need an improved operating system that can easily be updated to provide changing functionality, but it would not need any of the additional complex systems contemplated in current discussions of a redesigned nodal market.

Transmission and Distribution Service Providers ("TDSPs") must continue accelerated efforts to improve the capabilities of the grid. While it is unlikely that the economic nirvana of a completely uncongested grid will ever be reached, all market participants will benefit from a robust grid that will evolve from one that was originally not designed for the purchase of remote generation. Until then, those who have benefited from reduced costs due to an under-built transmission grid, which is to say all Loads, must share in the costs of resolving future transmission congestion.

The recent ERCOT Cost-Benefit Study states that the implementation of a nodal design will reduce the average cost to produce one megawatt-hour of energy by 20 cents over the next 10 years.[23] The Backcast portion of the same Study has been described by the Cost-Benefit Study's author as a comparison of ERCOT's actual zonal operations in 2003 with "optimal

[23] Tabors-Caramanis & Associates, op. cit. p. 3-22, Table 3-4.

zonal" as represented in the GE-MAPS model.[24] If that is true, then the Backcast model indicates that the cost of each megawatt-hour might have been reduced by $3.70 had zonal been optimized in 2003.[25] These are savings available today for which one need not wait for the results of a nodal experiment.

5. UPLIFT EFFECTS

It is appropriate that the Commission consider all the costs uplifted to Loads in their entirety. Currently, Loads are burdened by $150 million per year in ERCOT administrative fees, $400 million per year in Ancillary Services, and $200 million per year in congestion costs.

The changes suggested herein will reduce both Ancillary Service costs and congestion cost uplift. Some of these costs will also be redirected to those who, by their action or omission, caused congestion and/or the need for additional Ancillary Services. These costs will not, however, be eliminated. On the other hand, neither will it be necessary to increase the ERCOT administrative fee to the levels that have been suggested if a nodal market is implemented.

CONCLUSION

COCL believes that Texas needs an improved electric market. However, any move to a nodal-based design will not achieve the improvements desired. The benefits of a nodal market over the current zonal one, if they exist at all, are measured in fractions of a percent.[26] The words of SBC as submitted in its Initial Comments[27] to the Commission regarding the Cost Benefit Study still ring true:

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[24] Ellen Wolfe of Tabors-Caramanis & Associates stated to the PUC in an Open Meeting on 18 February 2005 that the Backcast Model was a comparison of actual operations with "optimal" operations for 2003.

[25] Tabors-Caramanis & Associates, op. cit. p. 4-3, Table 4-2.

[26] Tabors-Caramanis & Associates and KEMA Consulting, Inc., op. cit., p. 3-22, Table 3-4.

[27] John Keller, SBC Reply Comments, Public Utility Commission of Texas, Project No. 28500, "Activities Related to the Implementation of a Nodal Market for the Electric Reliability Council of Texas," Jan. 21, 2005.

1. Locational Marginal Pricing will not result in an increase in electricity supply in congested areas.
2. Locational Marginal Pricing will not result in significant decreases in electricity consumption in congested areas.
3. Locational marginal pricing will have indirect negative effects that may not have been considered to date.

Nodal pricing design is a *financial settlement* design, not a physical operating design. The real-time choice of dispatch methods for generating units can be independent of how a market chooses to financially settle the results of its physical system operation.

COCL believes that the implementation of an improved zonal market, as described herein, represents a cost-effective, immediate, and equitable method to achieve the stated goal of increasing ERCOT market efficiency for all market participants. It will eliminate the need to spend millions today to implement a future, nebulous, nodal-based market. It will reduce the burden to Loads and it will create a more disciplined and reliable market.

There are some that would characterize the effort to improve the current zonal market as a "band-aid". They claim that ERCOT software cannot be adapted to unit-specific bidding. They claim that ERCOT software cannot be adapted for centralized unit commitment to eliminate incentives not to commit units. COCL would remind the Commission that the improved zonal market described herein, by using sub-QSEs for bus level bidding and dispatch, eliminates the portfolio problem, without requiring ERCOT software to be adapted to unit-specific bidding. COCL also believes that the proposed improved zonal market, by moving from generic payments to cost-based OOM payment, eliminates gaming without any need to adapt ERCOT software to centralized unit commitment. Finally, regardless of market design, COCL asserts that in a confined market such as ERCOT, only the commitment of regulatory authority can insure a disciplined and equitable environment that will serve as a platform for a sustainable market. Such regulatory commitment can be brought to bear on the zonal market.

COCL strongly urges the Commission to consider the third path proposed herein as an alternative to the limited options evaluated in the Cost-Benefit Study. Improving the still evolving zonal-based design is a much more effective use of the time, money, and expertise of ERCOT's staff and stakeholders for improving the electric market and, at the very least, it deserves equal consideration with a nodal-based design which simply will not accomplish the Commission's stated goals. Saving a solid $3.70 per megawatt-hour today makes much more sense than chasing an ethereal 20 cent per megawatt-hour reduction in the future.

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Respectfully submitted,

Nikolaus K. L. Fehrenbach, with permission PCS

Nikolaus K. L. Fehrenbach, Chairman
Committee of Concerned Loads
Manager of Regulatory Affairs and
Utility Franchising
City of Dallas
1500 Marilla, Room 4 F North
Dallas, Texas 75201