FINAL REPORT

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Update on the ERCOT Nodal Market Cost-Benefit Analysis

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DISCLAIMER

The information contained herein is based on sources believed to be reliable and is written in good faith. Given the ongoing evolution of the issues addressed in this report, limitations on data availability and on the ability of any analytical models to capture all the realities of the existing or future electricity market, this report should not be considered a complete and definitive identification of assessed costs and benefits of the ERCOT nodal market beyond those developed under the assumptions and with the use of models and data explicitly documented in the report.

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1. EXECUTIVE SUMMARY

1.1. BACKGROUND AND OBJECTIVES OF THIS UPDATE

CRA International, Inc. and Resero Consulting ("CRA/Resero") were retained by the Public Utility Commission of Texas ("PUCT" or "the Commission") to prepare an update on the 2004 Cost-Benefit Assessment of the Texas Nodal Market[1] ("2004 CBA") prepared by Tabors Caramanis & Associates ("TCA") and KEMA Consulting. According to the 2004 CBA findings, the projected quantifiable benefits of the nodal market implementation within the ERCOT footprint significantly outweighed nodal market implementation costs: the estimated net present value of system-wide benefits over the first 10 years of operation of the ERCOT nodal market was approximately $587 million in production cost savings (in real 2003 dollars). The estimated costs of implementing the Texas nodal market were between $108 million and $157 million, including both ERCOT's and market participants' costs. In addition, the 2004 CBA identified a net present value ("NPV") of approximately $7.3 billion of consumer savings attributable to the nodal market re-design. The assumed nodal operations ("Go Live") date in that study was January 1, 2005.

The Texas Nodal Market ("TNM") implementation has experienced a number of delays and the expenditures to date and going-forward estimated costs significantly exceed those assumed in the 2004 CBA. Additionally, a number of new generating units have been added and several transmission upgrades made. Today's expected market conditions, including fuel prices, further transmission upgrades, and generation unit development are also different than those in the 2004 CBA. This updated Cost Benefit Assessment ("updated CBA", or "update") was commissioned to provide an indication of the incremental costs and benefits given changes that have transpired since the 2004 CBA was competed and the Commission's subsequent decision to implement a nodal market.

The objective of the 2004 CBA was not only to compare costs and benefits of the TNM implementation but also to provide a comprehensive assessment of the impact of the TNM on the efficiency of market operation, on individual geographical regions within the ERCOT footprint, on specific segments of the ERCOT power system, and on specific groups of market participants.

The scope of this update is much narrower, and is intended:

- To perform a four-year time-horizon study to re-assess overall system-wide production-cost benefits and determine the extent to which the 2004 CBA benefits may have changed;

1 Market Restructuring Cost-Benefit Analysis, Final Report to Electric Reliability Council of Texas, November 30, 2004.

- To determine expected implementation costs based on better, more specific, ERCOT TNM budget projections and to update expected market participant implementation costs based on a sample of market participant-reported projections; and

- To determine whether any post-2004 information substantially changes other costs, benefits or risks relative to the 2004 CBA.

The updated CBA is intended to provide information to allow the projected updated benefits to be compared to the net projected costs of continued TNM implementation and future operations, while simultaneously limiting the analytical cost and schedule impact caused by performing the assessment itself. Given that some TNM costs have already been incurred, CRA/Resero focused the analysis and report prospectively, providing an assessment of how the future net costs-to-continue compare to future potential benefits for the TNM.

1.2. Summary of Findings

The quantitative findings of this study are summarized in this section, and include a comparison of the estimate of going-forward costs and benefits of the TNM for the period of 2009 through 2020 inclusive. The results in Table 1 indicate that the estimated NPV of costs to continue the implementation and operation of the TNM is $222 million. The NPV of generation cost savings, determined as part of the updated CBA, is estimated to be $339 million. In addition, the implementation of the TNM is expected to result in additional savings based on improved generation siting decisions. While the updated CBA with its limited study horizon did not directly measure the impact of siting benefits, these benefits were estimated based on the 2004 CBA as modified by the CBA update analysis. The overall benefit, including benefits from improved generation siting, is projected to be $520 million.

Table 1: Estimated Going Forward Costs and System-Wide Benefits of TNM Implementation

NPV of net costs to continue (2009-2020)

	$Million real 2008 dollars
ERCOT	195
Market Participants	27
Total Costs	222

NPV of quantified system-wide benefits (2009-2020)[2]

	$Million real 2008 dollars
Benefits due to improved generation dispatch	339
Benefits due to improved generation siting	181
Total system-wide benefits	520

These updated results indicate that on a going-forward basis, the overall system-wide benefits outweigh the net costs of completing the TNM program. Similarly to the 2004 CBA findings, CRA/Resero estimates that TNM implementation will provide a significant reduction in consumer wholesale payments for electricity that exceeds the projected TNM costs. The savings to consumers are estimated to be approximately $5.6 billion (NPV) over the first ten years of operation of the nodal market, more than twenty times the projected TNM cost. The consumer benefits do, however, reflect a transfer in wealth from generators to consumers and not simply a system-wide benefit derived from more efficient electricity production and delivery.

The update of the other costs and benefits suggests that, as in the 2004 CBA, other benefits of the TNM are likely to exceed other costs and risks, and the CBA update suggests that these other benefits are likely to be even greater in total than those characterized in the 2004 CBA.

1.3. METHODOLOGY

Similarly to the 2004 CBA, this update includes the three major components summarized below.

Energy Impact Assessment (EIA)—quantified impacts to the energy market, system dispatch, and resulting production system costs. The methodology of the EIA component of the update was narrowed but not simplified relative to the 2004 CBA. While focusing specifically on the modeling assessment of only system-wide benefits of the TNM, CRA/Resero applied the same methodology for modeling generation dispatch and generation costs as was used in the 2004 CBA. All modeling input data and assumptions were updated to reflect the most current and reliable information on the ERCOT electrical grid, load forecast, generation fleet, and anticipated market conditions.

Implementation Impact Assessment (IIA)—provided quantitative and qualitative treatment of implementation startup costs, ongoing costs, and other transition-related impacts for ERCOT and its market participants. This IIA update was based on analysis of relevant

2 Benefits for years 2009 and 2010 were set to zero.

implementation cost information, both historical and projected, provided by ERCOT personnel, and a sample of market participants data collected directly by CRA/Resero .

Other Market Impact Assessment (OMIA)—provided an update on the qualitative treatment of a variety of other measures of impact not captured directly in the EIA or IIA by examining new information and market events lending to an updated understanding of other costs, benefits, and risks.

1.4. ENERGY IMPACT ASSESSMENT

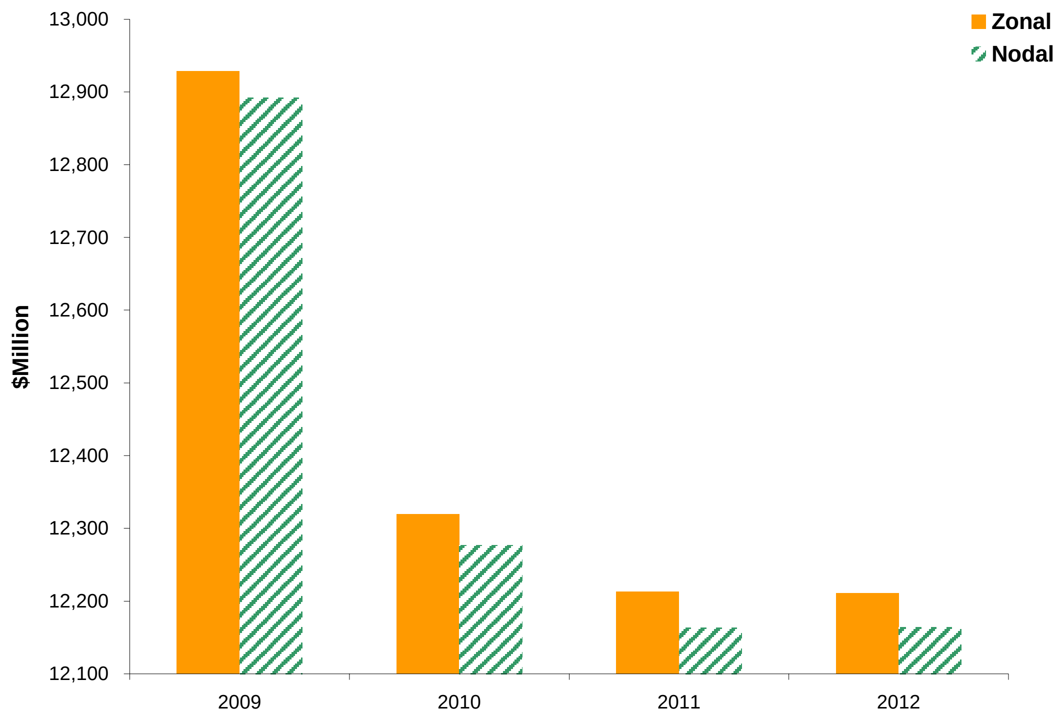
CRA/Resero conducted an update of the quantitative Energy Impact Assessment (EIA) of the ERCOT system under two scenarios: a status quo case (“Base Case”) in which ERCOT continues to schedule and settle based on a zonal market design, and a case in which ERCOT implements a nodal market design (“Change Case”). Similarly to the 2004 CBA, the EIA used the GE-MAPS model and incorporated the operating procedures and operational and physical transmission constraints currently used (Base Case) or intended to be used under the nodal design (Change Case).

The results of the analysis are based on model representations which generally follow the spirit and modeling techniques of the 2004 CBA. Input assumptions, however, were updated based on the current status of the ERCOT power grid and current expectations regarding demand growth, transmission upgrades, new generation additions and fuel price forecasts. These input assumptions were developed in close consultation with ERCOT operations, planning, and data management staff.

CRA/Resero performed simulations of the generation dispatch under the nodal and zonal market assumptions for the four-year period 2009-2012. Given the new start date of the nodal market, only results for 2011 and 2012 are directly applicable. The results for 2009 and 2010 have been provided for illustrative purposes.

Annual production cost is the primary economic indicator measured in this CBA update. The production cost difference clearly reflects potential social benefits (social welfare gain) to the ERCOT footprint of the nodal market design, and it is easy to interpret. Figure 1 shows the total annual production cost under each case. In the years simulated, the nodal market structure results in a lower cost of production (fuel, variable O&M, start-up and environmental permit/credit costs) to serve the demand than does the zonal market structure.

Figure 1: Annual Production Cost ($Million)



The production cost reduction (attributed to the improved efficiency in generation commitment and dispatch) during the first two years of TNM operations is estimated to be between $47 and $49 million.[3] The NPV from 2011 to 2020[4] is estimated to be $339 million, assuming that production costs and resulting benefits observed for the first two years of operation remain at the same level on average through 2020.

Additional production cost savings are expected from the improved siting of new generation under the nodal market structure. Based on the 2004 CBA results, improved generation siting increases annual benefits in years when prospective new generation is added, by 70% on average.[5] In the years 2013-2020, additional generation capacity will be needed to serve ERCOT demand, apart from the announced and in-development entry that is included in the analysis. The 70% ratio is applied to the values calculated for 2009-12, to account for the

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3 Values shown are in 2008 real dollars. The NPV calculations assume 8% nominal discount rate and 3% rate of inflation, the same assumptions as used in the 2004 CBA.

4 The NPV is calculated as a twelve-year NPV over the period of 2009 through 2020, assuming zero benefits in the first two years of this period.

5 This projection is based on the assumption that siting benefits in relative terms are not reduced by recent transmission upgrades nor are they reduced by changes in any of the other assumptions - such as fuel price and load growth - in the updated CBA.

benefit of siting future generation with the benefit of nodal signals. This raises the estimated annual benefits to $81.6M, or 70% higher than the $48M realized in 2011-12. Based on this approach, the resulting estimated twelve-year (2009-2020) NPV of production cost savings is $520 million (benefits in two years preceding the launch of the TNM are set to zero in this NPV calculation).

Additionally, the transition to the nodal market results in significant consumer cost reductions. This reduction in consumer payments, and a corresponding reduction in generator receipts, results from several changes which will occur with the TNM implementation, as illustrated in Table 2: Composition of wholesale costs to consumers in ERCOT under the Zonal and Nodal Market. With the transition from the zonal to the TNM structure, consumers avoid Out-Of-Merit ("OOM") payments made to generators and receive additional CRR auction revenues associated with congestion costs on local (intra-zonal transmission constraints).

Table 2: Composition of wholesale costs to consumers in ERCOT under the Zonal and Nodal Market

Composition of wholesale costs to consumers in ERCOT		Zonal	Nodal
Hourly load X hourly price	+	Zonal price	Load weighted zonal price
Out of Merit Payments	+	Yes	No
Refund of inter-zonal congestion rent via CRR auction	-	Yes	Yes
Refund of local congestion rent via CRR auction	-	No	Yes

The 2004 CBA estimated the NPV of reduction in consumer payments at $7.1 billion over 10 years of nodal market operation. A large portion of this reduction, $4.5 billion, was attributed to the refund of the local congestion rent which indicates that the local congestion rent is a major driver of this consumer benefit. Based on a comparison of congestion rent estimates in the two studies, CRA/Resero estimates the NPV the consumer cost reduction for this update to be approximately $5.5 billion.

This reduction in consumer payments should not be characterized as a system-wide benefit derived from improved system efficiency, but rather a wealth transfer from generators to consumers. Never-the-less the consumer benefits were viewed as an important metric in the 2004 CBA.

1.5. Implementation Impact Assessment

The costs of the nodal market implementation have increased significantly since the original nodal CBA was completed in 2004. There are two principal components to the implementation costs: the costs incurred by ERCOT itself and those incurred directly by market participants. The bulk of the implementation costs have been (and are projected to be) incurred by ERCOT.

ERCOT has conducted detailed studies of its own implementation costs, and their estimates have been subjected to extensive review and scrutiny. This current study is explicitly not intended to review ERCOT's and market participants' estimates, but rather to synthesize their and market participants' information and analyze the net costs of proceeding with the TNM implementation. CRA/Resero relied upon ERCOT's cost and schedule estimates for this analysis. There has been debate regarding whether current budget estimates from ERCOT accurately reflect the ultimate cost-to-completion of the TNM implementation; the ERCOT estimates incorporate contingences, both temporal and financial, and CRA/Resero has relied upon estimates including those contingencies. The analysis was based on data received from ERCOT through December 9, 2008. Unless otherwise advised by ERCOT, all cost data was assumed to be in 2008 dollars, and unless otherwise noted, all values in this analysis are expressed in 2008 dollars.

As of the revised budget estimate from December 9, 2008, ERCOT's overall cost estimate for the start-to-finish implementation of the TNM is $660 million. Of that $660 million, approximately $309 million has already been spent, and approximately $351 million in direct expenditures remain.[6]

ERCOT's incremental increased costs to operate a nodal instead of a zonal market were estimated at $16 million in 2011 and $18 million in 2012. These costs consist principally of increased headcount and capital equipment and will remain relatively constant over the TNM timeframe. Based on ERCOT's guidance and CRA/Resero's analysis, the persistent incremental increase in operational costs is estimated to be $14 million and to remain constant in real terms through the study timeframe.

It is critical to note that if the TNM project were to be halted, there would be a number of deferred upgrades and refresh costs associated with continued operation of the zonal system; stopping is not free. These costs include updated software, related labor expenses, and improvements that have been deferred because of the pending TNM implementation. ERCOT has estimated these costs at $160 million. In addition to these zonal refresh costs; ERCOT has also estimated that there would be additional $15 million in contract termination and other administrative costs, placing total "unwinding" costs at roughly $175 million. These represent the costs that ERCOT would incur if the TNM implementation were halted today. These costs were assumed to be incurred in 2009, or immediately upon termination of the TNM program.

6 Late on December 9, 2008, ERCOT provided an updated already-spent figure of $322.1 million. The analysis has been conducted with a consistent set of numbers from Ron Hinsley's December 9, 2008 ERCOT board presentation, in which the already-spent total was $309 million.

The estimate of total start-to-finish market participant implementation costs is $175 million, of which approximately $103 million is estimated to have already been spent. Market participant unwinding costs are estimated to be approximately $42 million. Insufficient information was available to accurately estimate ongoing incremental cost increases for market participants, and so we have not factored these ongoing increased implementation costs into our analysis. As a result, our analysis potentially underestimates the overall TNM cost impact on market participants.

The following table presents a summary of ERCOT's and market participants' costs associated with each option. This table is expanded upon in later sections.

Table 3: Summary of TNM implementation costs, 2008 dollars

Item	Cost (million)	Description & Notes
Total overall nodal costs	$660	Total start-to-finish cost of TNM implementation, including interest expenses
Overall spent to date	$309	As of December 2008, including interest
2011 incremental nodal cost	$16	Additional cost to operate nodal over zonal in 2011
2012 incremental nodal cost	$18	Additional cost to operate nodal over zonal in 2012
2013-2020 incremental nodal cost	$14	Additional cost to operate nodal over zonal in 2013-2020
Nodal demobilization & zonal refresh costs	$175	Amount to halt TNM implementation ($15) and refresh zonal systems ($160)
NPV of ERCOT's implementation cost through 2020, including increased ongoing incremental costs, excluding future finance charges	$362	
NPV of MPs' implementation cost through 2020, excluding increased ongoing incremental costs	$67	
NPV of ERCOT's de-mobilization and zonal refresh costs	$167	
NPV of MPs' de-mobilization and zonal refresh costs	$41	
NPV of ERCOT's net TNM implementation cost	$195	Net cost to continue for ERCOT versus stopping
NPV of MPs' net TNM implementation cost	$27	Net cost to continue for MPs versus stopping
Overall NPV cost to continue TNM implementation through 2020	$222	Net cost for ERCOT and MPs to continue TNM implementation versus halting TNM program today

The overall net cost to completion, $222 million, represents the net overall cost to continue the TNM implementation compared to halting and returning to the zonal market. Said differently, this is the total expense that could be avoided if TNM implementation were to be halted today.

1.6. Other Market Assessment

CRA/Resero also performed an update of the other nodal market costs, risks and benefits outside of those costs and benefits captured in the Energy Impact Assessment and the Implementation Impact Assessment. This update reflects new impacts that were not recognized or identified at the time of the 2004 CBA, and other impacts that were recognized in the 2004 Other Market Impact Assessment (OMIA) but for which the availability of more recent information may offer new insights about the nature, degree, or significance of the impacts.

The OMIA update did not identify any substantially new types of impacts, nor did it reveal that the other impacts of a nodal market are significantly different from the way they were characterized in the 2004 CBA OMIA. Several of the 2004 OMIA findings were substantiated through the review of updated information and events. At the same time, the updated information suggests that some of other risks and costs appear to be less significant now than they were when the 2004 OMIA was prepared. The 2004 OMIA suggested that the net impact was positive, i.e., that there appeared to be additional benefits beyond those captured in the quantitative elements of the CBA. The current OMIA update suggests, to an even greater degree, that these other impacts are net positive.

Specific insights are summarized as follows.

Events and the changing environment in ERCOT have identified several Other Market Impact changes:

a. Given the experience that market participants have gained since the 2004 OMIA was prepared, many of the potential risks associated with the nodal market have largely been resolved or mitigated. Although the market is perceived to be more complicated than originally envisioned, market participants have also acquired a better understanding of likely market dynamics through their readiness activities and by participating in the various stakeholder groups.

b. The value of the nodal market is potentially higher as a result of the significant deployment of wind generation, given the nodal market's ability to alleviate limitations of ERCOT's current dispatching procedures and to provide for rapid system response.

c. Analysis of the summer price excursions by ERCOT's IMM offers several observations, including that the zonal market may have difficulty in addressing some zonal congestion situations, resulting in high cost impacts, and that nodal markets offer customers more efficiency, choice and flexibility.

Market outcomes from other U.S. nodal markets substantiate the algorithmic and complexity risks identified in the 2004 OMIA. They also suggest that these risks and their impacts decrease over time as market participants and market operators become more aware and take appropriate corrective actions. Similarly, while nodal markets are still not able to capture all of the theoretically available benefits of nodal price signals, ongoing refinements of market rules and algorithms have, over time, led to increased benefits from better price signals.

Resolution of market monitoring policies suggests there are reduced nodal market risks associated with price anomalies and market manipulation. The addition of co-optimized ancillary services suggests these too may provide additional benefits that were not captured in the 2004 CBA.

2. ENERGY IMPACT ASSESSMENT

CRA/Resero conducted an update of the quantitative Energy Impact Assessment (EIA) of the ERCOT system under two scenarios: a status quo case ("Base Case") in which ERCOT continues to settle based on a zonal market design and a case in which ERCOT implements a nodal market design ("Change Case"). Similar to the 2004 Cost-Benefit Analysis ("2004 CBA"), the EIA used the GE-MAPS model and incorporated the operating procedures and operational and physical transmission constraints currently used (Base Case) or intended to be used under the nodal design (Change Case).

The GE-MAPS model is a security-constrained dispatch model that simulates the operation of the electricity market over time. It assumes short-run marginal cost bidding, performs a least-cost dispatch subject to thermal and contingency constraints, and calculates hourly nodal prices of electricity.

The results of the analysis are included in this Section. These results are based on model representations which generally follow the spirit and modeling techniques of the 2004 CBA. However, all input assumptions have been updated based on the current status of the ERCOT power grid and today's expectations regarding demand growth, transmission upgrades, new generation additions and fuel forecast. These input assumptions have been developed in close consultation with ERCOT operations, planning, and data management staff.

2.1. OBJECTIVES OF THIS UPDATE

The objective of this update of the EIA is to re-evaluate the system-wide benefits of the nodal market structure in order to allow for an updated assessment of benefits relative to the nodal market costs. In the 2004 CBA, the EIA analysis considered a 10-year timeframe, focused on a wide spectrum of system-wide regional economic indicators of nodal redesign and measured the impact of the nodal market on various market participants, including consumers, generation owners, investor owned utilities, and municipal utilities and electric cooperatives.

The EIA update, on the other hand, was not undertaken in order to conduct an entirely new cost-benefit study. Rather, the objective was to verify whether the direction and the magnitude of estimated benefits have changed given the current state and anticipated changes of the ERCOT power grid. As a result, the focus of this update is substantially narrower than the 2004 CBA, analyzing only system-wide benefits over a two-year period 2011-2012 in order to quantify benefits through market simulations, projecting other measures of benefits where possible.

Section 2.4.1 of this report contrasts objectives of this update of the EIA analysis with objectives of the 2004 CBA.

2.2. Potential Benefits of a Nodal Market Design

As was discussed in the 2004 CBA, there are several energy impacts of a shift to a nodal market design including:

- More efficient and transparent dispatch of resources;
- Improved management and pricing of local congestion;
- Improved siting of new resources.

The transition to a nodal market design improves and streamlines the process of security constrained commitment and dispatch of generating units and therefore is expected to result in lower generation costs than the market design currently in place. Lower production costs will ultimately benefit electricity consumers in ERCOT. The simulation analysis discussed below directly quantifies these benefits.

Treatment and pricing of local congestion under the nodal market design results in significant consumer benefits, as explained in section 2.4.3. This impact was carefully studied in the 2004 CBA. In this update, only the magnitude of the congestion rent refund to be received by consumers under the nodal design is quantified, rather than the entire impact on consumers' costs of served load. The latter is presumed to accrue consistent with the congestion rent refund.

Different price signals provided by the nodal and zonal markets also affect future generator siting decisions. In the 2004 CBA, this impact was addressed quantitatively. In this EIA update, the siting benefits are projected based upon the relative siting and dispatch efficiency benefits estimated in the 2004 EIA.

Other impacts, such as transparency and volatility associated with market changes outside of those measured in the EIA, are addressed in Section 4, Other Market Impacts.

2.3. Measuring Benefits with the Energy Impact Assessment

In this update, CRA/Resero quantified economic benefits of the nodal market design using a single metric, a change in production costs within the ERCOT footprint. Production costs considered included:

- Fuel costs;
- Non-fuel variable operating and maintenance costs;
- Costs of environmental allowances (where applicable);
- Start-up generation costs; and
- Costs of power purchases from outside of ERCOT offset by revenues from power sales to the outside of ERCOT.

Under the Base (Zonal) Case, congestion on Commercially Significant Constraints ("CSCs") is managed based on estimating the impact of generation and load schedules on these constraints using average shift factors. When the impact is measured using average shift factors, the result is always approximate and ERCOT operators have to be conservative in deploying generating units intended to resolve local congestion so that actual flows through a CSC will not violate the CSC's operating limit. That can affect the efficiency of generation dispatch. In the Change (Nodal) Case, by including all constraints in a single optimization, the added conservatism is not necessary and there is an increase in the economic efficiency of generation dispatch, which results in a lower total cost of producing electricity.

2.3.1. Modeling Input Assumptions

The following types of input assumptions were used in the EIA.

- An hourly demand forecast by ERCOT weather zone, provided by ERCOT;
- An updated forecast of fuel prices;
- A transmission system configuration based on annual load flow representations that include all planned transmission upgrades, as provided by ERCOT;
- Environmental adders based on expected environmental regulations; and
- New thermal and wind generation additions already under construction, based on information from ERCOT.

Section 2.4.2 of this report provides a comparison of input assumptions used in this update with those used in the 2004 CBA.

Details of these and other inputs to the model are described in Appendix A.

2.3.2. Overview of Base and Change Cases

Similar to the 2004 CBA, the EIA compared two scenarios: a Base Case, assuming no implementation of a nodal market, and a Nodal (or Change) Case, representing operations with ERCOT with a nodal market in place.

The essential differences between the Base and Change Cases relate to: (1) how congestion is cleared and (2) the treatment of portfolio scheduling under the Base Case vs. no portfolios under the Change Case. In the Change Case a pure nodal optimization is performed across the ERCOT region. In the Base Case, the ultimate unit commitment and dispatch under the ERCOT's existing zonal model is simulated. In the 2004 CBA, analysis of the Base Case also included modeling of zonal prices and assessment of OOME and OOMC payments. That analysis was necessary to measure the impact of nodal design by sector and by category of market participants. Given the system-wide focus of this update, while the zonal market system cost was modeled, zonal prices and OOME/OOMC payments were not analyzed.[7]

Detailed discussions for each major market attribute are provided in the sections that follow.

The updated EIA used the same commitment and dispatch logic as the 2004 CBA.[8] It is likely that that the 2004 CBA did not fully capture all the benefits of centralized unit commitment provided by the TNM implementation.[9] This update uses the same modeling logic as the 2004 CBA. To the extent the 2004 CBA understated the benefits of centralized unit commitment, this update would also understate this benefit.

2.3.3. Transmission Congestion in Base and Change Cases

Base Case Representation

The objective of the Base Case modeling is to reflect the way that ERCOT manages zonal and local congestion in today's market environment, which generally follows a three-step process:

Step 1. Estimation of zonal congestion and energy balance.
Step 2. Resolution of local congestion, subject to results of Step 1.

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7 Modeling of zonal prices and OOME payments requires a significant amount of additional modeling work and post processing. Parties did not believe that extending the change in benefits to sector and region warranted the added expense and study duration.

8 The GE-MAPS feature of committing and dispatching generation resources ERCOT-wide was used in both cases. The objective was to capture all the economic transactions that currently take place among various entities in ERCOT, and those to be expected following implementation of the Texas Nodal Model (TNM). Doing this represents an assumption that outside of the market structure influences, the wholesale electricity market in the ERCOT is currently efficient and that the TNM will not increase the efficiency of the trading market. (This is a conservative assumption that does not capture the increased efficiency, if any, of the ERCOT market that would arise from implementing the TNM in ERCOT.) The GE-MAPS model first solves the unit commitment problem for the next day using a heuristic approach and then solves for the hourly dispatch using a linear programming approach to achieve the least-cost, most efficient hourly dispatch subject to all reliability constraints for that unit commitment solution. The transfer capabilities (i.e., transmission constraints) of the transmission lines and major interfaces are inputs to the model and are based on the thermal capabilities of the transmission system, or the equivalent transfer limits for voltage and stability constraints.

9 An implicit assumption underlying the 2004 CBA is that in the absence of transmission constraints, the generation scheduling process of the current market structure results in an optimal unit commitment. This assumption is very difficult to prove or disprove. If the current zonal market commitment is sub-optimal, developing an unambiguous approach to simulate it would be very difficult.

Step 3. Final resolution of zonal congestion and energy balance subject to results of Step 2 and formation of zonal prices.

The Base Case modeling in this update was consistent with the Base Case modeling in the 2004 CBA.

In the 2004 CBA the representation of this three-step process was emulated with the use of two instances of the GE-MAPS model, one simulating the results of Step 1 above and calculating zonal prices, the other simulating the outcome of Steps 2 and 3. Custom built post-processing software was then used for calculation of the Out-of-Merit Order settlements. However, the ultimate dispatch and generation costs were determined with the use of the second instance of GE MAPS simulating the outcome of Steps 2 and 3. In the current analysis, only the second instance of GE MAPS was used to model the Base Case, since the focus of this update was on the impact on system-wide production costs only and the calculation of prices and Out-of-Merit Order settlements was not required.

A special emphasis was placed on the development of ERCOT's operational limits to be used in the representation of Commercially Significant Constraints (CSCs) in GE MAPS modeling of the current system. CSC limits were set below their respective Total Transfer Capabilities (TTCs) to replicate the operational rule used by ERCOT in managing inter-zonal congestion involving average shift factors. In reality, ERCOT's Operational (OC1) limits change minute by minute along with market conditions. In simulating the zonal market, CRA assumed that TTCs remain constant over time and that OC1 limits remain constant within a year but are adjusted annually. The annual reduction in transmission capacity approximating the difference between TTC and OC1 operating limits was calculated using the following analytical process:

- ERCOT market was simulated using GE MAPS with CSC limits set at their TTC (OC0) levels. From that simulation, the hourly generation for each unit and hourly flow through each CSC was reported (simulated CSC flow).

- Using hourly generation and hourly load in each congestion zone, a flow on each CSC was estimated with the use of Average Weighting Shift Factors (AWSFs) for each zone (estimated flow). This computed hourly estimated flow on each CSC replicates the results of the operator calculation of that flow in each hour when a zonal representation of the ERCOT network is being used.

- For each CSC constraint, critical operating hours were identified as hours in which either the simulated or estimated flow was above 90% of the TTC for that constraint. For these hours CRA/Resero computed the average difference between simulated and estimated flow, and an absolute value of the difference between an hourly deviation and average difference. The latter represents an estimate of the hourly error which the operator could make while managing CSC congestion using AWSFs instead of actual shift factors.

- Using the sample of possible hourly errors, CRA/Resero identified the 99th percentile in that sample and used it as an adjustment to the CSC limit to be implemented in GE MAPS. In other words, this adjustment guarantees than in any critical hour the probability for the flow on the CSC, when managed via a zonal representation of the grid, to actually exceed its TTC is less than 1%, i.e. such a problem may arise only in 1 hour out of 100.

- The above calculation was performed separately for each simulated year, 2009-2012.

Table 4 provides the TTC limits. CRA/Resero derived operational limits for each modeled CSC and for each simulated year.

Table 4: CSC TTCs (OC0) and Derived Operational Limits (OC1)

	CSC1: West→North	CSC2: South → North	CSC3: North→South	CSC4: North→Houston	CSC5: North →West
TTC[10] (MW)	811	530	933	1439	610
2009 OC1 (MW)	646	530	742	1277	610
2010 OC1 (MW)	640	530	740	1274	578
2011 OC1 (MW)	584	530	610	1247	471
2012 OC1 (MW)	587	530	572	1263	507

The GE-MAPS simulation combines the resolution of all local constraints using actual shift factors subject to honoring CSC constraints based on the CRA/Resero-derived OC1 physical limits (as if addressed in the zonal framework using average shift factors) as well as all contingency constraints associated with all CSC Closely Related Elements (CREs). In this simulation, spinning reserves and regulation were co-optimized in the model to reflect recent changes to the ERCOT market.

Change Case Representation

The Nodal Case simulations were performed using GE-MAPS security constrained unit commitment (SCUC) and dispatch algorithms with all economic constraints enforced. CSC constraints were honored at their respective TTC (OC0) levels shown in Table 4. The Change Case simulation also modeled spinning and regulation reserves as co-optimized.

10 Source: ERCOT, 2009 Annual Zonal ATC, SCS, TTC and Total TCR Report. TTCs were assumed to remain constant in all simulated years. TTC values used are Operating Capacity (OC0).

2.3.4. Summary of Quantified Results

The results of the EIA analysis are summarized in this section. All financial values shown in this section are expressed in real 2008 U.S. dollars.

The quantification of benefits from the GE-MAPS analysis is based on comparisons between the Base and Change cases and focuses solely on the change in generation production cost, a primary economic indicator of improved market efficiency. Other metrics reported in the original study were not directly measured. Where possible, a discussion of the potential impact on such indicators is provided in Section 2.4 of this report.

Time Horizon of Quantified Benefits

CRA/Resero performed simulations of generation dispatch under the nodal and zonal market assumptions over a period of four years 2009-2012. Given the new start date of the nodal market, only results for 2011 and 2012 are directly applicable to this update. The results for 2009 and 2010 are provided for illustrative purposes only.[11]

Explanation of Benefits

The following metrics are provided to characterize the energy impacts. Each metric is discussed below.

- Physical metrics: comparison of quantities of supply system-wide, by zone and generation mix.
- Cost metrics: production costs, including generation costs, and net cost of power purchases from outside of ERCOT.

Physical Metrics

The total generation is essentially the same in the Base and Nodal Cases because there is little interchange between ERCOT and surrounding regions. The differences can be attributed to small changes in imports or exports (given the representation of import/export flows as dependent upon the ERCOT price). Figure 2 shows the sum of generation and net import in each simulated year.

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11 CRA/Resero, PUC Staff and ERCOT agreed on the 2009 to 2012 time horizon for the update during the scoping process. This timeline was selected because it was believed to (a) focus on validating the benefits associated with the most fundamental and defensible type of benefit – the production cost savings – and validating those benefits believed to be most sensitive to completed transmission upgrades and other market conditions, (b) avoided the subjectivity associated with the siting decisions – decisions that resulted in significant debate during the 2004 CBA process, (3) provided a direct measure of benefits for those near-term years with the largest influence on an NPV metric, (4) avoided the need for, and subjectivity of, assessing transmission upgrades and generation additions in out years, (5) limited the cost of the study, and (6) allowed the study to be completed in a timely manner.

Figure 3 though Figure 6 show annual generation by zone under the Base and Change Case scenarios. As shown in these figures, under the nodal market generation increases in the West and North Zones and decreases in the South and Houston Zones. Improved congestion management provides better access to more efficient generation in the West and North and displaces less efficient generation in the Houston and South zones, resulting in overall lower generation costs.

Figure 2: Total Generation plus Net Import

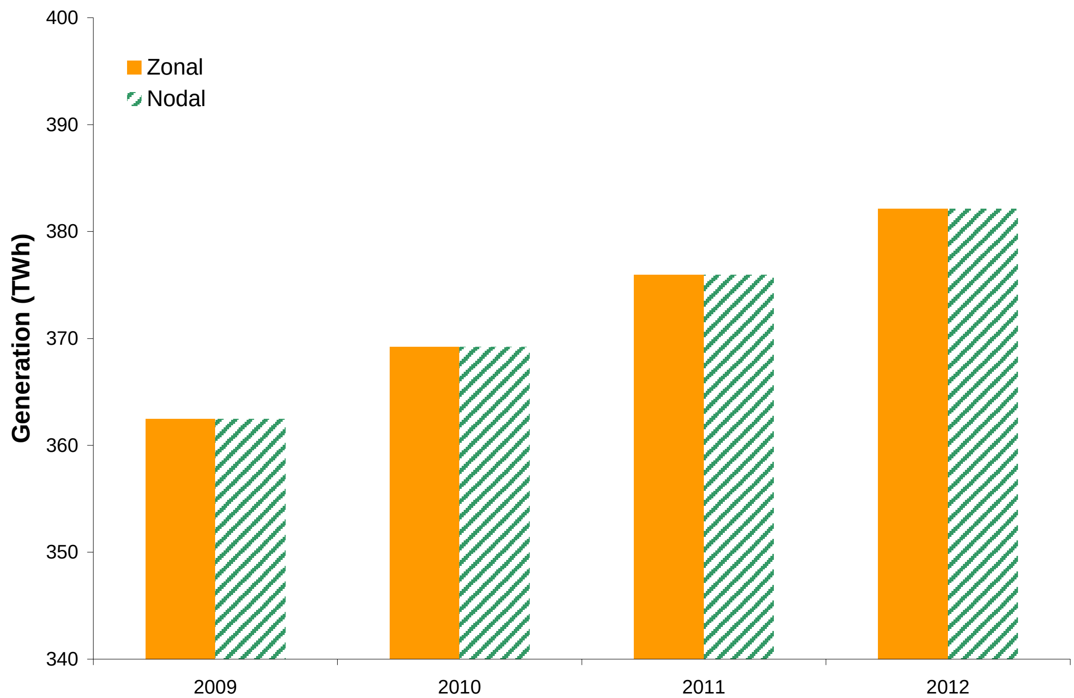


Figure 3: North Zone Generation

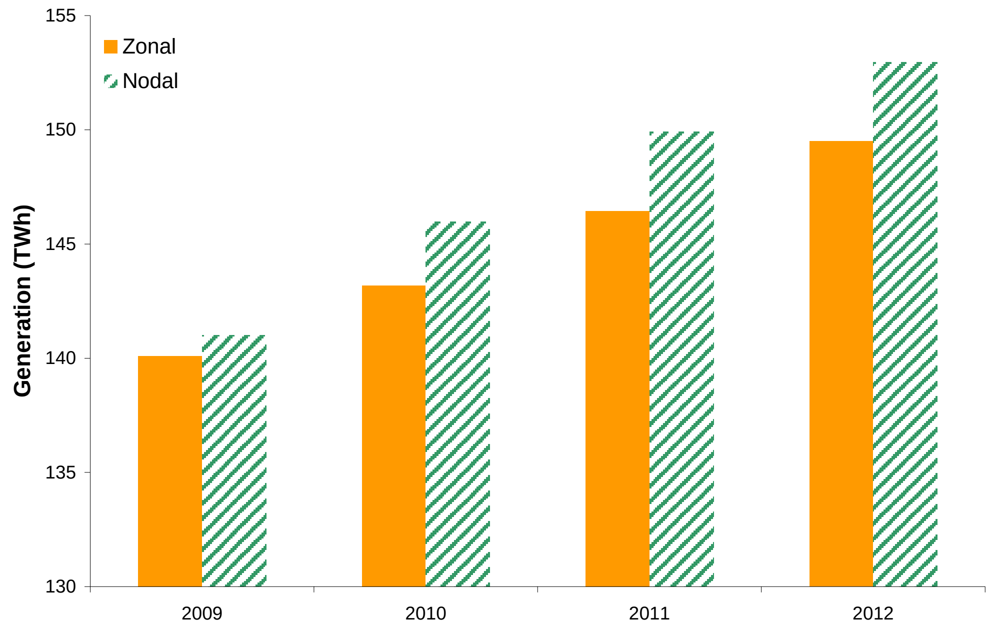


Figure 4: South Zone Generation

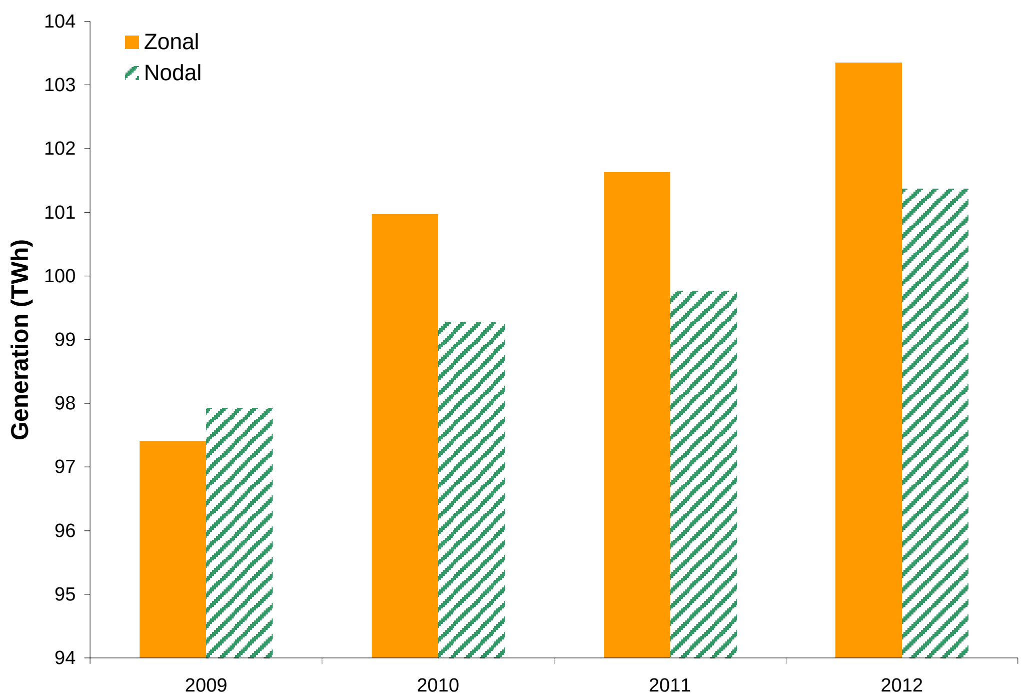


Figure 5: West Zone Generation

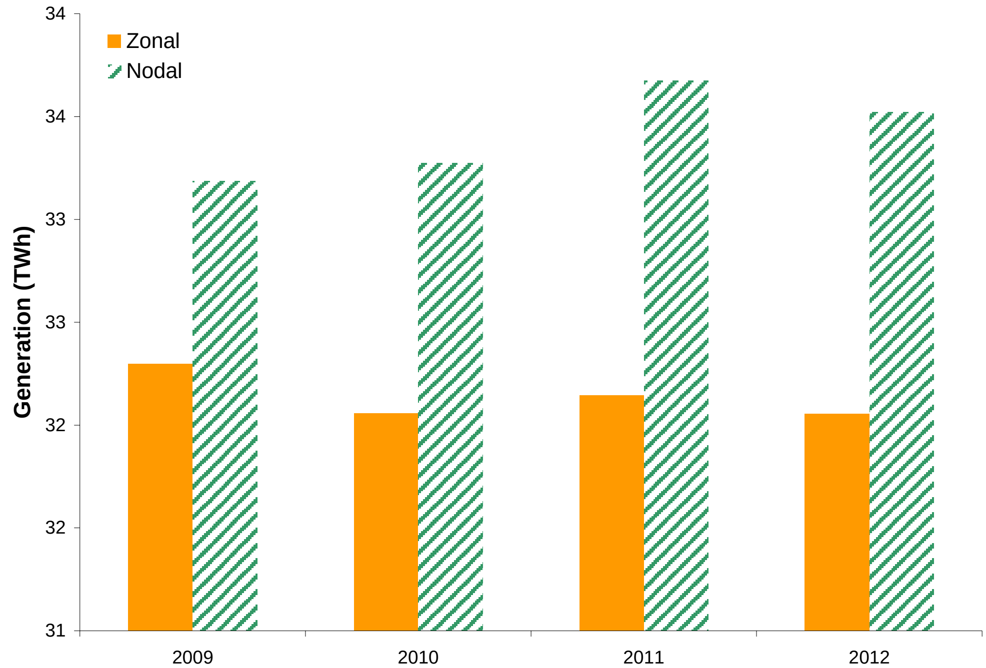


Figure 6: Houston Zone Generation

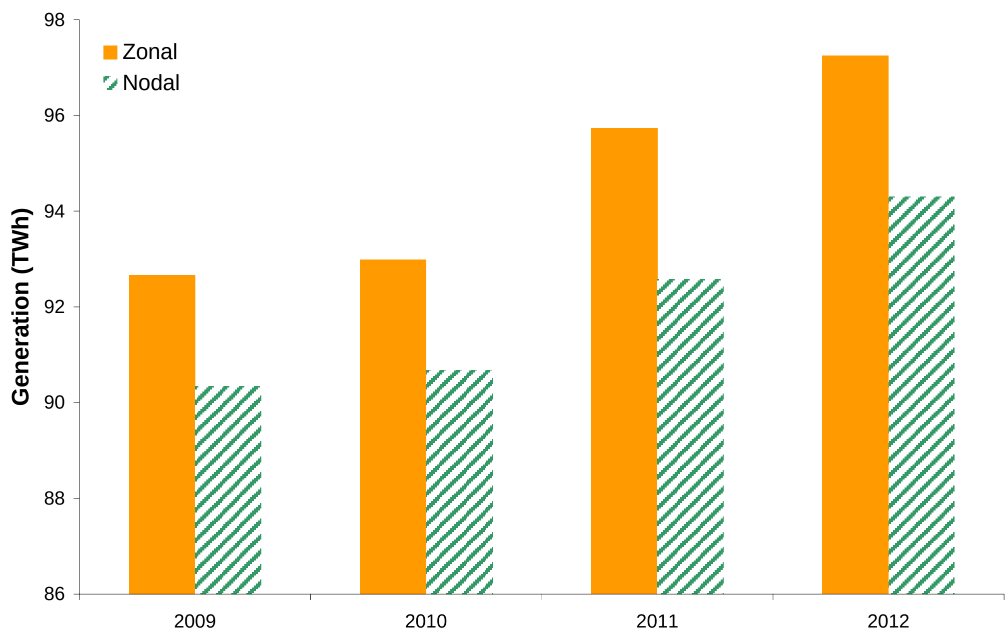
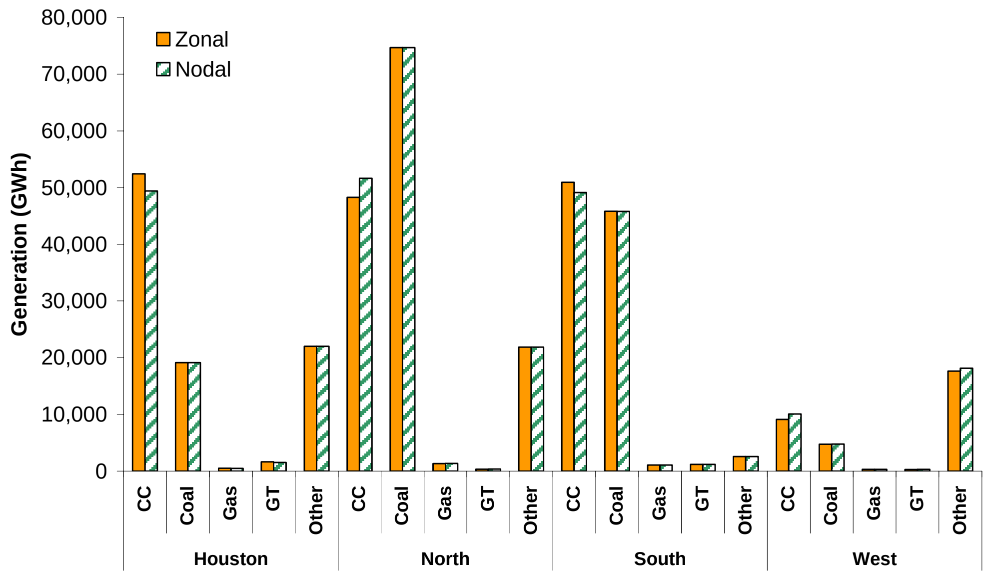


Figure 7 presents an analysis of the impact of the nodal market on the generation mix by zone in the first year of operation of the nodal market. As this figure demonstrates, implementation of the nodal market primarily affects the operation of Combined Cycle generating units (lower generation in Houston and South zones, higher generation in the North and West zones).

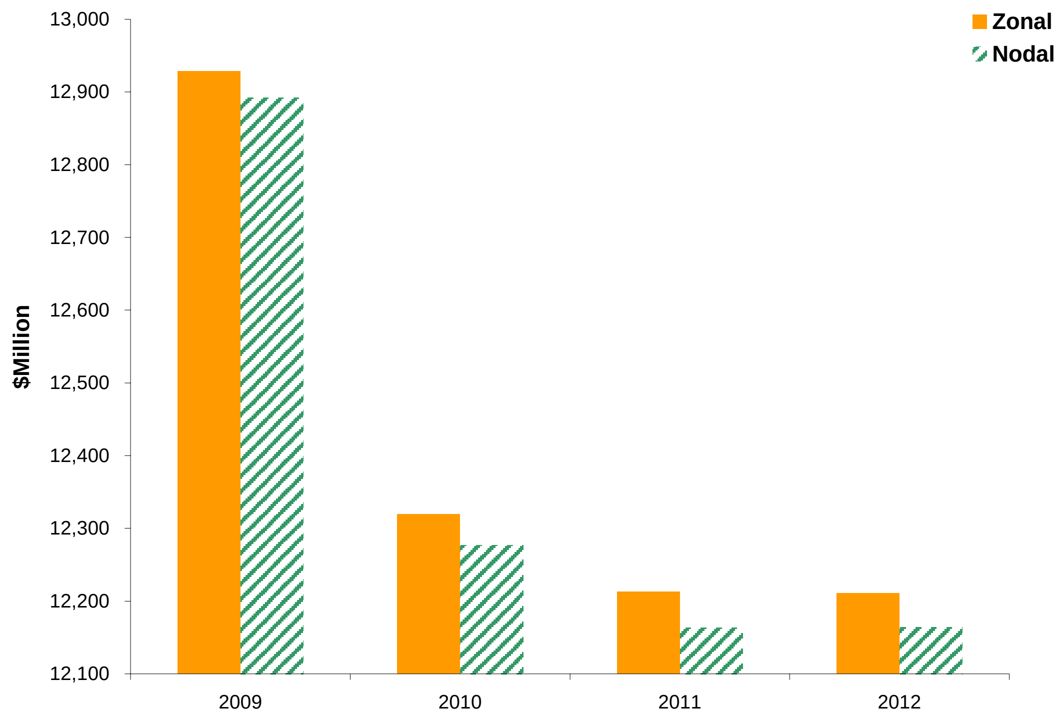
Figure 7: Generation Mix Comparison, 2011



Annual Production Costs – a Critical Economic Indicator

Annual production cost is a critical economic indicator. It is easy to interpret and it clearly represents a social gain (social welfare gain) to the ERCOT footprint as a whole. Figure 8 shows the total annual generation cost under each case. In simulated years the nodal market structure results in a lower cost of production (fuel, variable O&M, start-up and environmental permit/credit costs) than the zonal market structure.

Figure 8: Annual Production Cost



The benefit of the nodal market is calculated as the difference in production costs between Zonal and Nodal Scenario. Annual benefits are shown in Table 5:.

Table 5: Annual Production Cost by Scenario (in real 2008 dollars)

	Zonal Case ($Million)	Nodal Case ($Million)	Benefit (Zonal- Nodal) ($Million)
2009	*12,928.6*	*12,892.0*	*36.6*
2010	*12,319.2*	*12,277.1*	*42.1*
2011	12,212.8	12,163.6	49.2
2012	12,211.2	12,164.4	46.8
Average Annual (2011-2012)	12,212.0	12,164.0	48.0
Projected NPV (2011-2020)	86,378	86,039	339

The production cost reduction (attributed to the improved efficiency in generation commitment and dispatch) during the first two years of TNM operations is estimated at between $47 and

$49 million.[12] The measured benefits in 2009 and 2010, though not particularly relevant given the projected 2011 start date, are estimated to be smaller, $37 million in 2009 and $42 million in 2010. Higher benefits in future years could be attributed to a number of factors including increased electricity demand, generation additions, tightening of CSC limits or changing fuel prices. No single factor has been determined to be responsible for this result.

Under the assumption that production cost benefits observed for the first two years of operation of the nodal market were to remain on average at the same level over first ten years of operation, (i.e. annual benefits of $48 million over a period of 2011 through 2020), the 2011 to 2020 NPV of benefits is estimated to be $339 million. The NPV is calculated for the period of 2009 through 2020, zero benefits are assumed in years 2009 and 2010.

2.4. Comparison with the 2004 Cost-Benefit Analysis

This Section provides a brief comparison of objectives, methodologies, and results between the 2004 EIA and the EIA update.

2.4.1. Comparison of Study Objectives

The objective of the 2004 CBA was to provide a comprehensive assessment of the impact of the Texas nodal market implementation on the efficiency of market operation, on geographical regions of the ERCOT footprint, on various segments of the ERCOT power system, and on various groups of market participants. As described above, the objective of this EIA update is focused on assessing whether there are significant changes in the direction and magnitude of system-wide benefits vis-à-vis costs, given information presently available.

Table 6 shows a comparison of the study intentions between the 2004 CBA EIA and the CBA EIA update.

Table 6: Comparison of EIA Objectives

	2004 CBA	2008 Update
Time Horizon	2005-2014	2011-2012, illustrative simulations for 2009-2010
Types of Benefits Captured	Production cost savings due to efficient dispatch Production cost savings due to more efficient siting of new generation	Production cost savings due to efficient dispatch
Assignment of benefits	System-wide, regional, by sector	System-wide only
Backcast analysis	Performed Backcast for 2003 to verify model discrepancies with market if any. (No discrepancies were identified)	None

12 Values shown are in 2008 real dollars, and the NPV calculations assumes 8% nominal discount rate and 3% rate of inflation, the same assumptions as used in the 2004 CBA.

2.4.2. Comparison of Input and Modeling Assumptions

Table 7 identifies the similarities and differences in the modeling approach used in the 2004 EIA vis-à-vis EIA update. As shown in this table, the modeling approach of the 2008 update has been narrowed but not simplified. CRA/Resero applied the same methodology for modeling generation dispatch and generation costs in both studies.

Table 7: Modeling Approach, 2004 CBA and 2008 Update

Modeling Approach	2004 CBA	2008 Update
Zonal Market Modeling	Two instances of the GE MAPS model, one used to simulate ultimate dispatch, another to compute zonal price and Out-of-Merit settlements. Elaborate post-processing tools to compute pricing and revenue payments resulting from OOME settlement.	One instance of GE MAPS used to simulate ultimate dispatch only
Nodal market modeling	GE MAPS simulations with full transmission representation of ERCOT and nodal pricing	GE MAPS simulations with full transmission representation of ERCOT and nodal pricing
Sector impact analysis	Elaborate data mapping and post-processing for the sector impact analysis	None required
Modeling of generation siting decisions	A stand-alone model to select a technology and location subject to market pricing structure	None used
Backcast	GE MAPS model, collection, processing and mapping of historical hourly data on generation output and outages	None required

The differences in results are driven by the difference in input data outlined in Table 8.

Table 8: Input Assumptions, 2004 CBA and 2008 Update

Input Assumption	2004 CBA	2008 Update
Load forecast and representation	ERCOT EIA-411 for peak and energy, 2003 historical load shapes, load represented by congestion zone	ERCOT hourly load forecast by weather zone
Transmission representation	ERCOT load flow cases, 2004 series	ERCOT load flow cases, September 2008 series
New entry assumptions	ERCOT CDR, 2004	ERCOT CDR, 2008, Energy Velocity, ERCOT planning department
Fuel price forecast	2004 mid-year outlook	EIA Annual Energy Outlook 2008
Modeling of Commercially Significant Constraints (CSCs)	2004 TCR Report, reduced CSC limits for the Zonal model	2009 TCR Report, reduced CSC limits for the Zonal model
Representation of inter-zonal transmission constraints	ERCOT contingency analysis for the 2004 TCR report	ERCOT contingency analysis for the 2009 TCR report
Representation of local transmission constraints	ERCOT identified constraints in UPLAN model from 2004 analysis, TCA contingency analysis for the contingency list provided by ERCOT, monitored most transmission lines	ERCOT identified constraints in UPLAN model from 2008 analysis, CRA contingency analysis for the contingency list provided by ERCOT, monitored most transmission lines
Backcast	GE MAPS model, collection, processing and mapping of historical hourly data on generation output and outages	None required

2.4.3. Highlight of Changes in the ERCOT System and in the Market Outlook between 2004 and 2008

The ERCOT power grid has changed in the last four years since the 2004 CBA was prepared. Significant changes were made to its physical infrastructure that influenced the outcome of the updated EIA. The most important changes include the addition of over 2000 MW of thermal generation capacity, predominantly consisting of gas-fired combined cycle generation technology.[13] In addition, between 2005 and 2008 transmission owners invested over $2.8 billion in upgrading the ERCOT high voltage transmission infrastructure by adding over 3000 miles of in new high voltage transmission lines and over 30,300 MVA in new transformer capacity.[14]

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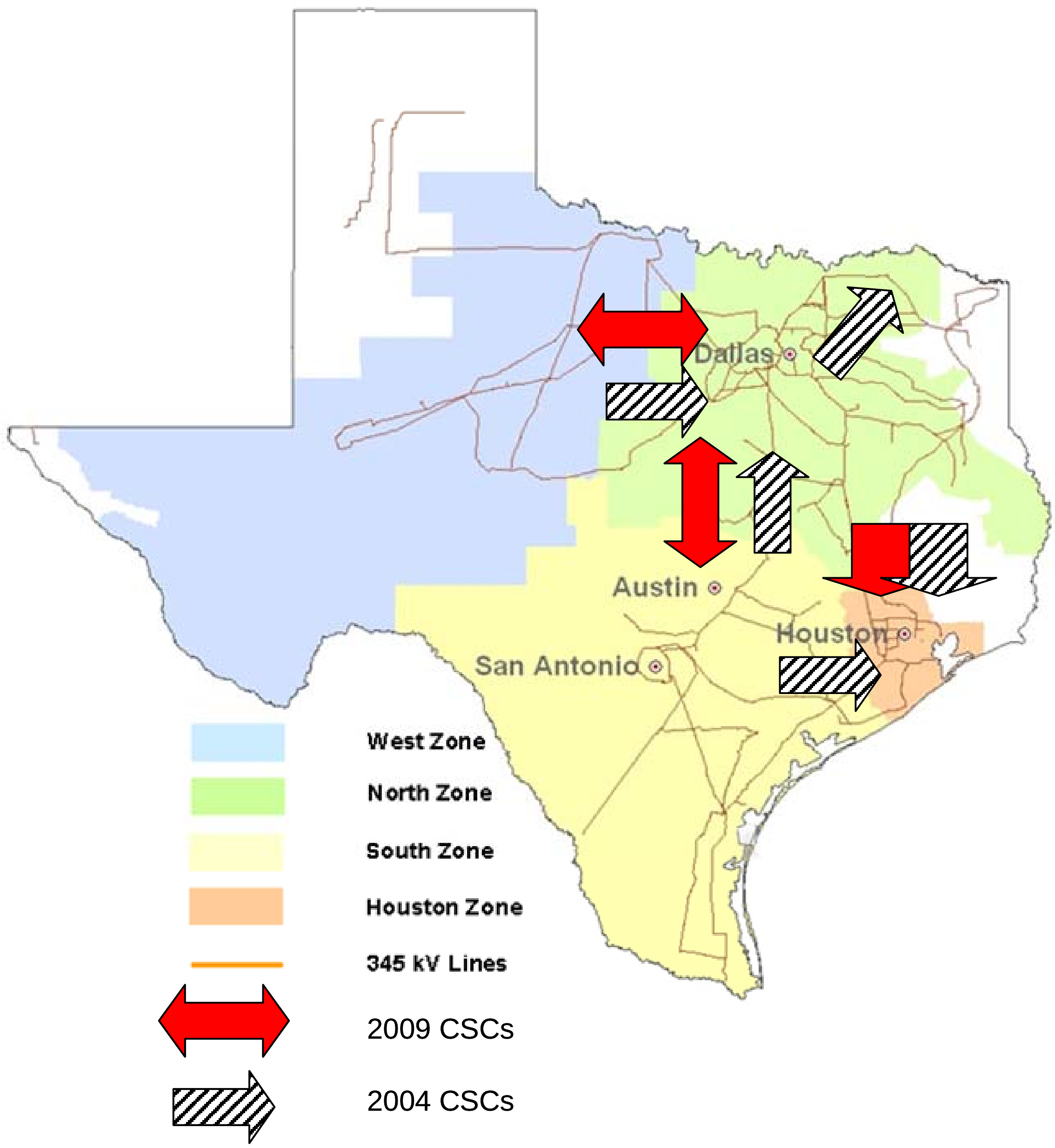
13 Source: CRA Database, Energy Velocity Database.

14 Source: CRA analysis of ERCOT Transmission Project Information Tracking (TPIT) reports.

These generation and transmission upgrades, in conjunction with other system and market changes, resulted in the redefinition of Commercially Significant Constraints (CSCs) between ERCOT congestion zones as shown on Figure 9. Changes in ERCOT transmission and generation infrastructure also resulted in a shifting of major inter-zonal transmission bottlenecks. For example, a South-to-Houston CSC, which was one of the most critical transmission constraints in the 2004 CBA, is no longer considered a CSC. The 2004 CBA analysis also included a Northeast congestion zone separated from the North zone by a CSC. The current definition of congestion zones and CSCs no longer includes this distinction.

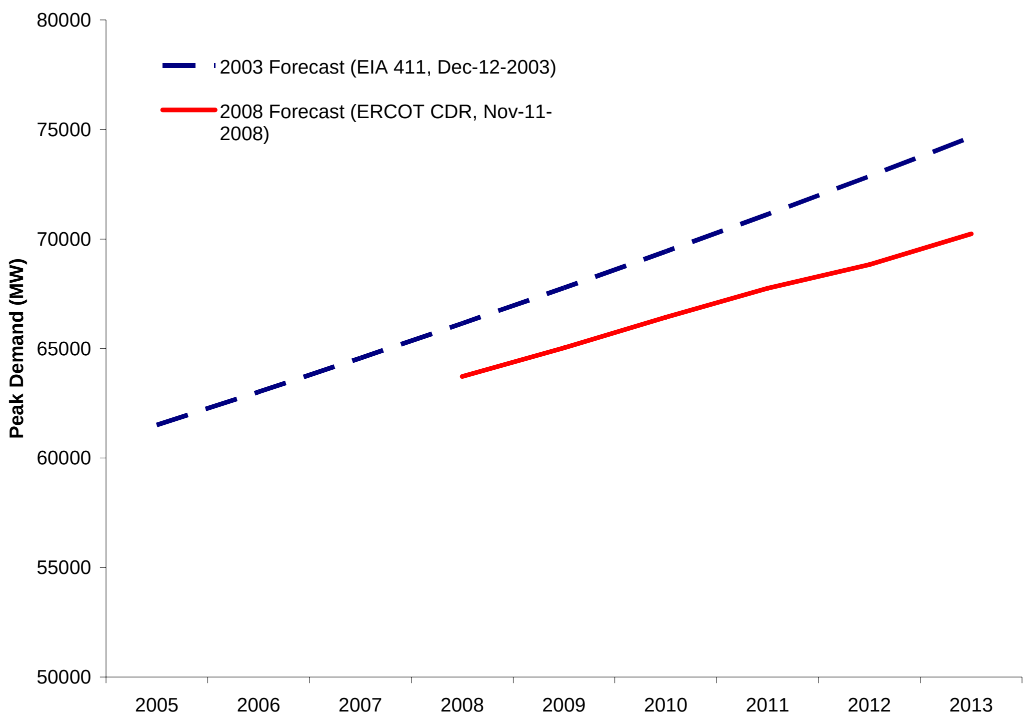
Figure 9. Comparison of ERCOT CSCs Definitions: 2004 CBA vs. 2008 Update



At the same time, unidirectional CSCs between West and North and South and North Zones have been replaced by bi-directional CSCs between these zones. Finally, the electrical definitions and transfer capabilities of CSCs in the 2008 update differ significantly from those defined for the 2004 CBA.

There are significant changes in the market outlook between the 2004 CBA and 2008 Update. In particular, the 2008 Update uses a substantially lower demand forecast compared to the forecast that was underlying the 2004 CBA as shown in Figure 10.

Figure 10. Peak Demand Forecast: 2004 CBA vs. 2008 Update[15]



Peak demand projected for 2008 per the most recent ERCOT Capacity, Demand and Reserves (CDR) report is 2,419 MW lower than the 2003 forecast for that year prepared in 2003.[16] This forecast reduction and the addition of over 2000 MW of new generation capacity and significant transmission improvements are significant drivers causing a reduction in estimated nodal market benefits relative to the 2004 CBA.

15 Does not include behind-the-fence load.

16 Approximately 50% of this discrepancy is attributed to Load Acting As Reserves (LAARs) subtracted from the 2008 forecast.

On the other hand, the outlook for future natural gas prices also changed dramatically between 2004 CBA and the 2008 Update as shown in Figure 11. High natural gas prices used in the 2008 Update are expected to increase total production costs and will likely increase benefits from the nodal (if everything else were held equal between two scenarios).

Figure 11. Comparison of Natural Gas Price Forecast, 2004 CBA and 2008 Update. (Houston Ship Channel, all prices are shown in real 2008 $/MMbtu)

In sum, changes in ERCOT infrastructure and market conditions are likely the cause of the lower estimate of benefits from the TNM implementation. The only exception is the outlook of fuel prices: an increase in fuel prices over the 2004 CBA creates upward pressure on generation costs and on the estimated TNM benefits. As discussed in the next section, the net impact of these changes results in lower benefits than those estimated in the 2004 CBA.

2.4.4. Comparison of Results

Impact on Annual Production Costs

The results of the ensuing discussion are summarized in Table 9.

Table 9: Annual Average Production Cost Savings Comparison, 2004 CBA and 2008 Update

Category of Savings	2004 CBA ($ Million in 2003 dollars)	2008 Update ($ Million in 2008 dollars)
Savings from improved generation dispatch (per year)	66.8	48.0
Savings from improved generation siting (per year)	47.2	33.6
Total NPV savings (first 10 years of operation)	587[17]	520

The 2004 CBA identified net present value system benefits over the first ten years of nodal market operation at $587 million in 2003 dollars, which corresponds to approximately $675 million in 2008 dollars. Generation cost savings, determined as part of the updated CBA, are estimated to be $346 million. In addition, the implementation of the TNM is expected to result in additional savings based on improved generation siting decisions.

These benefits from improved siting are estimated to be substantial. For example, in the 2004 CBA average annual production costs savings over first four years of analysis did not include generation additions based on new siting decisions. Estimated annual average benefits over that period were $66.8 million (in real 2003 dollars). Over the next four years of analysis, average benefits of the nodal market were $114 million (in real 2003 dollars) or 1.7 times higher than in the first four years. The 70% increase in benefits ($47.2 million) can be attributed to the improvement in generation siting decisions which were modeled for the second four years of analysis in the 2004 CBA. Assuming 70% in additional benefits attributable to improved generation siting over a period of 2013 through 2020 (when generation capacity will be needed in addition to the new entry included in the analysis through 2012), the NPV of these additional benefits amounts to $184 million. Based on this estimate, the resulting estimate of the NPV of production cost savings for a ten-year period 2011-2020 is computed to be $520 million ($339 million in dispatch and commitment savings and $181 million in siting savings). This is $155 million (or 23%) lower than the $675 million benefit identified in the 2004 CBA.

Impact on Consumers

This impact can only be assessed qualitatively, because no zonal prices and out-of-merit settlements were simulated in this update. However, as discussed earlier, transition to the

17 The referenced CBA NPV of production cost savings covers the entire ten-year study period. However, as discussed in the 2004 CBA report, simulation results for the last two years were significantly influenced by transmission overloads, rendering estimates of production cost savings for those years less reliable than for the first eight years of the analysis. Generation savings from improved dispatch and generation siting are reported for the first eight years only.

nodal market results in the transfer of funds from producers to consumers in the form of auction revenues for CRR rights associated with congestion on local transmission constraints.

The transition to the nodal market results in a significant reduction in consumer costs. This cost reduction in consumer payments (and a corresponding reduction in generator receipts) is a result of several changes which will occur with the TNM implementation illustrated in Table 10. As shown in this table, with the transition from the zonal to TNM structure, consumers avoid Out-Of-Merit ("OOM") payments made to generators and receive additional CRR auction revenues associated with congestion costs on local (intra-zonal transmission constraints).

Table 10: Composition of wholesale costs to consumers in ERCOT under the Zonal and Nodal Market

Composition of wholesale costs to consumers in ERCOT		Zonal	Nodal
Hourly load x hourly price	+	Zonal price	Load weighted zonal price
Out of Merit Payments	+	Yes	No
Refund of inter-zonal congestion Rent via CRR auction	-	Yes	Yes
Refund of local congestion Rent via CRR auction	-	No	Yes

The 2004 CBA estimated the NPV of reduction in consumer payments at $7.3 billion over 10 years of nodal market operation (in 2008 dollars). A large portion of this reduction, $4.5 billion was attributed to the refund of the local congestion rent, which indicates that the local congestion rent is a major driver of this consumer benefit (it represents 63% of the total consumer benefit).

Table 11 compares congestion rent attributed to the local congestion over the first four simulated years of the current update (2009 through 2012) and the 2004 CBA (2005 through 2008). On average, local congestion rent in the 2004 CBA was 29% higher than estimated in the current update as shown in this table. As a rough approximation, this analysis can be used to estimate the potential impact on consumers under the current update as being $5.6 billion (a 29% reduction from the 2004 CBA estimate of $7.3 billion).

Table 11: Estimated Local Congestion Rent under Nodal Scenario: 2004 CBA vs. 2008 Update (real 2008 dollars)

	Local Congestion Rent – Update ($Million)	Local Congestion Rent – 2004 CBA ($Million)
2009 (2005)	660.2	630.6
2010 (2006)	503.5	929.9
2011 (2007)	526.1	679.3
2012 (2008)	616.6	732.5
Average Annual	576.6	743.1
Per cent	100%	129%

Impact on Producers

The 2004 CBA provided estimated impacts on operating margins for generators as a whole which were estimated to lose approximately $6.6 billion over first 10 years of operation on a net present value basis (in 2008 dollars). As stated earlier, estimated consumers' gain of $5.6 billion is a wealth transfer from producers. That, however, is partially offset by reduction in production costs, $0.52 billion. Therefore, estimated in this update net producers' loss is $5.08 billion. In sum, this update indicates an approximately 30% smaller loss in operating margins for generators than an estimate reported in the 2004 CBA.

2.5. CONCLUSIONS

Based on the updated EIA, the NPV of system-wide benefit from the nodal market over first ten years of its operation are estimated as follows.

- $339 million in system-wide benefits attributable to improved generation dispatch;
- $520 million in system-wide benefits attributable to improved generation dispatch and generation siting;
- $5.6 billion in consumer benefits to electricity end users in ERCOT;
- $5.08 loss in revenues accrued to generators in ERCOT.

3. IMPLEMENTATION IMPACT ASSESSMENT

3.1. OBJECTIVES

The purpose of the Implementation Impact Assessment ("IIA") update is to update the estimated cost impact of the nodal implementation program on both ERCOT and market participants, including determining which costs are unrecoverable, properly attributable only to the nodal project, or not otherwise accounted for.

The IIA update is explicitly not intended to analyze the reasons that the overall costs have increased and the schedule has been delayed, but rather to collect and synthesize the information useful to assess costs and benefits associated with going forward with the TNM implementation.

Two alternatives were considered in the updated IIA: continuing with TNM implementation to completion, and halting the TNM implementation and reverting to a zonal market.[18]

3.1.1. Options

Continue TNM Implementation

While the actual calculation of implementation costs is exceptionally involved and requires considerable planning and effort, using this information to calculate the cost of continuing development of the TNM is relatively simple, as it involves future costs only, and no recoverable costs. Note that while ERCOT budgets include financing costs, the IIA update results are presented in terms of NPV and are therefore independent of financing costs under the assumption that the discount rate applied reasonably reflects ERCOT's financing costs.

It was necessary for CRA/Resero to estimate those ongoing ERCOT operating costs that would exceed those needed for ERCOT to operate a zonal market; these costs were not addressed in detail in the ERCOT budget documentation supplied to us. An estimate of ongoing, persistent, incremental ERCOT operating costs associated with the TNM was developed with ERCOT's assistance based upon CRA/Resero's analysis. These costs are an important component of the total TNM going-forward implementation cost.

18 Deferring the decision to continue or halt the TNM implementation is theoretically an option as well. However, ERCOT's projections of nodal spending for calendar year 2009 are approximately $122 million, most of which would be unrecoverable should the nodal program be terminated. At the same time, it is not expected that benefits, if calculated in the future, would be found to be significantly higher. Deferring the decision therefore does not seem like a prudent alternative and was not assessed in this update.

Halt Nodal Implementation

The alternative case considered was the option of halting the TNM implementation. Care was taken to ensure proper treatment of this alternative case.

While direct TNM implementation costs would decrease relatively quickly (there are some outstanding fixed price contracts, but the majority of costs are month-to-month), two principal costs would be incurred:

- Demobilization/termination costs;
- Deferred zonal refresh/update costs.

The first set of demobilization costs includes the administrative costs associated with halting the program. ERCOT has generally preferred to engage in contracts that are terminable quickly rather than longer-duration contracts, and as a result, contract termination costs are relatively low. Similarly, the majority of contractors and labor are engaged on an at-will basis, and could be released quickly. In our discussions, ERCOT has indicated that there are no major outstanding penalty clauses or payments to vendors that would need to be paid in the event of a nodal program halt.

ERCOT program management is currently working on developing a formal estimate of these administrative demobilization costs. At this time, they have estimated costs of \$5 to \$20 million, and upon ERCOT's recommendation, an estimated cost of \$15 million was used in the IIA update.

3.2. SUMMARY OF FINDINGS

The costs of the nodal market implementation have increased significantly since the original nodal CBA was completed in 2004. There are two principal components to the implementation costs – the costs incurred by ERCOT itself and those incurred directly by market participants. The bulk of the implementation costs have been incurred by ERCOT, and as a result, the updated analysis focused on understanding the TNM costs and schedule. ERCOT has conducted detailed studies of its own implementation costs, and their estimates have been subjected to extensive review. This analysis was explicitly not intended to re-calculate and review ERCOT's and market participants' estimates, but rather to synthesize information and properly analyze the net costs of proceeding with the TNM implementation. CRA/Resero relied upon ERCOT's cost and schedule estimates for this analysis.

ERCOT has included temporal and financial contingency factors in its estimates. CRA/Resero included these contingencies in the overall cost; contingency factors are routinely a portion of large, complex project budgets, and these contingency factors have been included in this analysis.

ERCOT's incremental costs to operate a nodal instead of zonal market were estimated at $16 million in 2011 and $18 million in 2012. These costs consist principally of increased headcount and capital equipment, and are estimated to remain constant over the TNM timeframe. Based on ERCOT's input and our analysis, CRA/Resero has estimated that the incremental increase in operational costs of $14 million persists at a constant rate in real terms.

If the TNM project were to be halted, there would be a number of deferred upgrades and refresh costs associated with the zonal system. These include updated software expenses, labor expenses, and improvements that have otherwise been deferred because of the pending TNM implementation. ERCOT has estimated these costs at $160 million. In addition to these zonal refresh costs; ERCOT has also estimated that there is approximately another $15 million in contract termination and other administrative costs, placing total "unwinding" costs at approximately $175 million. These represent the costs that ERCOT would incur if the TNM implementation were halted today, and these costs were assumed to be incurred in calendar year 2009, or immediately following a decision to halt TNM implementation.

While lower than ERCOT's, market participants' costs are an important factor in the overall analysis. Based on interviews with market participants, the overall start-to-finish costs for market participants was estimated at $175 million, and the net remaining cost to continue for all market participants were estimated at $29 million.

The following tables present a detailed summary of key ERCOT and market participant costs. These tables, grouped under Table 12, are principally intended to show the source and derivation of the cost calculations. All values are in 2008 dollars.

Table 12: Source and derivation of calculations performed

Line	Item	Cost	Derivation	Source	Description
1	Total direct nodal project costs	$526,082,911		12/9 Hinsley board presentation	Total start-to-finish cost of nodal program less financing costs
2	Indirect backfill labor	$7,891,180		same	Labor diverted from other projects at ERCOT
3	Indirect support costs	$18,464,948		same	Indirect support costs from ERCOT overhead
4	Facilities support allocation	$8,005,567		same	Indirect facilities allocation from ERCOT overhead

5	Finance charges	$99,555,393		same	Financing charges if project is to continue to conclusion assuming total recovery
6	Total overall nodal costs	$659,999,999	Sum of lines 1-5	same	Total end-to-end cost of TNM implementation through 2014
7	Overall spent to date	$308,784,025		12/9 board presentation	Includes $11.3 million of interest charges
8	Interest spent to date	$11,286,700		same	
9	Non-interest spending to date	$297,497,325	Line 7 - line 8		
10	Interdependent (recoverable) costs	$39,700,000		ERCOT communication	Costs attributable to shared infrastructure – “recoverable” if TNM halted
11	Non-recoverable costs to date	$269,084,025	Line 7 - line 10		To-date spending less portion recoverable for shared infrastructure
12	2011 incremental nodal cost	$16,177,849		CRA/Resero Analysis, ERCOT communication	Additional cost to operate nodal over zonal in 2011
13	2012 incremental nodal cost	$18,016,912		same	Additional cost to operate nodal over zonal in 2012
14	2013 & 2014 incremental nodal costs	$28,398,757		same	Additional cost to operate nodal over zonal in 2013 and 2014
15	Direct costs remaining for TNM	$351,215,974	Line 6 - line 7		How much left to spend from today on, under current budget projections
16	Non-interest direct costs remaining	$262,947,281	Line 15 - (line 5 - line 8)		Direct costs minus future financing costs
17	Interest costs	$88,268,693	Line 15 – line 16		Not included in

	remaining				going-forward NPV calculation
18	Nodal demobilization costs	$15,000,000		ERCOT communication	Amount to terminate TNM program
19	Zonal refresh costs	$160,302,375		ERCOT communication	Deferred maintenance and refresh costs

Table 13: presents the analysis of remaining implementation costs through 2020.

Table 13: Calculation of ERCOT & MP TNM implementation costs through 2020, 2008 dollars, 4.85% real discount rate[19]

	ERCOT implementation costs	ERCOT increased ongoing incremental costs	Market participant implementation costs
2009	$167,214,918		$45,778,838
2010	$94,904,345		$25,982,195
2011	$828,018	$16,177,849	$226,689
2012		$18,016,912	
2013		$14,199,379	
2014		$14,199,379	
2015		$14,199,379	
2016		$14,199,379	
2017		$14,199,379	
2018		$14,199,379	
2019		$14,199,379	
2020		$14,199,379	
Nominal Cost	**$262,947,281**	**$147,789,790**	**$71,987,721**
NPV	**$246,512,062**	**$115,782,538**	**$67,488,211**
		TOTAL:	**$429,782,812**

19 The real discount rate of 4.85% corresponds to the 8% nominal discount rate and 3% inflation rate assumption used to compute all NPV values in the EIA analysis

Based upon the analysis above, the total NPV of the cost to continue TNM implementation is estimated to be $430 million from 2009 through 2020.

Halting the TNM and instead continuing with a zonal market design, however, would incur additional costs; stopping is not free. Table 14: presents our calculation of the costs of halting the nodal program, including the costs of terminating the TNM and reverting to a nodal market design. Table 15 reflects the net impact of continuing with the TNM versus reverting to a zonal market design.

Table 14: Calculation of ERCOT & MP TNM halting costs through 2020, 2008 dollars, 4.85% real discount rate

	ERCOT de-mobilization and zonal refresh costs	ERCOT increased incremental operational cost	MP de-mobilization and zonal refresh costs
2009	$175,302,375[20]		$42,542,675
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
Nominal Cost	**$175,302,375**	**$-**	**$42,542,675**
NPV	**$167,186,524**	**$-**	**$40,573,107**
		TOTAL:	**$207,759,631**

20 This represents approximately $160 million in deferred zonal market (“refresh”) costs and $15 million in costs to “unwind” the TNM.

Table 15: Summary of net costs of TNM implementation through 2020 – 2008 dollars, 4.85% real discount rate

Item	Cost	Notes
ERCOT remaining TNM implementation cost through 2020 (NPV)	$362,294,601	
MP remaining TNM implementation through 2020 (NPV)	$ 67,488,211	
ERCOT demobilization & refresh costs (NPV)	$167,186,524	Unwinding costs, if relevant, were assumed to occur in the 2009, upon TNM program termination
MP demobilization & refresh costs (NPV)	$ 40,573,107	Unwinding costs, if relevant, were assumed to occur in the 2009, upon TNM program termination
Net cost to continue TNM implementation through 2020	$222,023,181	

In summary, the net going forward costs of continuing the implement the TNM are estimated to be $222 million and provides the basis for comparison with estimated TNM benefits.

3.2.1. Contributors to TNM Implementation Delays and Cost Increases

CRA/Resero reviewed ERCOT documentation and interviewed ERCOT TNM personnel to help summarize some of the principal contributors to the delayed implementation of the TNM. A key driver to the cost of the TNM is the labor effort, and this labor effort is strongly influenced by the time it takes to implement the TNM.

In retrospect the initial go-live date of January 2009 was overly aggressive; the final requirements had not been finalized, insufficient planning had been performed, and project controls that could identify implementation problems early did not exist, or were not sufficient.

The principal technical reason for delays that was cited, both in documentation and in our interviews, was the underestimate of the time and effort required to integrate multiple market systems. Upon implementation of the TNM, ERCOT opted for a best-of-breed approach, in which systems from multiple vendors were combined to form the overall nodal system. ERCOT was aware from the project's inception that the integration costs would likely be higher than for a single-vendor solution, but the costs proved to be significantly higher than expected. ERCOT also opted to skip integration testing; this decision later introduced numerous problems that led to inadequate quality of the TNM systems and forced a return to this testing later in the project.

One particular element of integration that proved especially difficult was the implementation of tools to handle Common Information Model (CIM) data that ERCOT requires to operate its market. This model codifies information about the physical power system, and is the key element for data exchange between operational systems. The project was started late, and turned out to be significantly more complex than anticipated by either ERCOT, AREVA, or ABB.

ERCOT also suggested that TNM delays were caused by delayed software deliveries early in the process that cascaded into future phases and interfered with the planned early delivery systems that were designed to give market participants early access to ERCOT's TNM systems.

3.2.2. Principal Risks for Further Delays

A significant schedule risk for additional TNM implementation delays is the need to incorporate additional TNM protocol revision requests. While our interviews with ERCOT have indicated that the rate of creation of new protocol revision requests is slowing, each one that ERCOT must address requires additional resources that may materially contribute to delays. Simultaneously, because of the TNM's delayed go-live date, there are additional zonal market improvements that must be implemented that divert resources from the TNM program.

A significant technical risk to the TNM schedule is the ability of ERCOT to manage the large volumes of data that will be required to support the nodal market. The necessary data storage and transfer requirements for the TNM are markedly higher than those of the zonal market, and ERCOT is currently in the process of implementing several approaches (including the Information Lifecycle Management (ILM) strategy) to address these risks.

Finally, while difficult to quantify, several market participants interviewed believed that ERCOT is not allocating sufficient time in its implementation schedule to allow market participants to "catch up" with ERCOT's TNM implementation changes. Several of these market participants felt that additional delays may result from this insufficient time in the schedule.

3.3. Analysis Notes

3.3.1. ERCOT

ERCOT cost information was primarily from ERCOT, including board-of-director presentations, internal calculations, and internal schedules. Public data was used to the extent possible. No independent verification of ERCOT's cost estimates was performed.

Zonal Refresh Costs

During the implementation of the nodal market, there have been certain costs and upgrades that have been deferred on the legacy zonal system, as well as some costs that would be necessary to update the zonal system to meet current market standards. ERCOT provided the following information regarding zonal refresh costs. More detailed information follows, referenced by notes provided by ERCOT.

Table 16: Zonal refresh costs

		Hours	Cost	Comments
Applications	EMS (1)	18,500	3,237,500	Retain Nodal EMS system - apply required Zonal updates - used blended labor rate
			1,500,000	Complete nodal EMS
	EMS hardware (1)		-	Assumes re-use of nodal hardware
	MMS (1)	3,750	656,250	Upgrade current Zonal MMS system - used blended labor rate
	MMS long-term solution (1)		60,000,000	Estimate is based on the effort for a forklift replacement of MMS.
	NMMS		2,000,000	Finish Nodal NMMS - perform schema analysis - modify application to work with Zonal schema
	COMS/Settlements		4,000,000	Apply performance enhancements to Settlement and Data Agg code in the Zonal system
	CRR		-	Return to TCR application - no cost to do this
	CMM		1,500,000	Adjustments would be needed to use CMM in the Zonal market
	MIS/EIP	7,300	4,277,500	Upgrade Texas Market Link (TML) ($3M), additional interface development
	OTS		1,400,000	Complete Operator Training Simulator - includes additional work on CIM

				importer ($300k)
	ODS / EDW	7,500	1,312,500	Changes to extracts, reports, etc.
Subtotal		*37,050*	*79,883,750*	
Integration			*10,000,000*	All nodal systems will require system and business process integration.25% of current nodal Integration budget of $42M
Changes shelved due to Nodal implementation	IMM requested modifications (2) (3)		25,000,000	Recommendations from IMM Assumes a $20M project of roughly twice the size of EMMS Release 4 + $5M of additional efforts
	Market PRRs/SCRs		4,000,000	Items shelved in recent years due to the upcoming Nodal implementation
Subtotal		-	*29,000,000*	
Additional support activities	Training / business process		3,000,000	Rough estimate
	Analysis & Design		4,970,938	25% applied to Applications subtotal (excludes MMS long-term solution)
	Project Management		1,988,375	10% applied to Applications subtotal (excludes MMS long-term solution)
	Contingency		31,459,313	35% applied to Applications subtotal and integration
Subtotal		-	*41,418,625*	

Total	**37,050**	**160,302,375**	

1. Projects to replace EMS and MMS systems would be required. Existing versions are no longer supported by vendor (Areva) on Tru64 platform. Total replacement of these systems is likely.

2. IMM Recommendations

3. IMM - 2007 State of the Market Report

Future Incremental Operating Costs

If ERCOT continues its implementation of the nodal market, there are incremental operating costs that it will incur after the transition from the zonal to the nodal market. These costs result from the increased complexity and size of the nodal market, and the need for additional staff.

ERCOT estimates it will need to employ the equivalent of approximately 50 new FTEs to operate the nodal market. These employees would be needed throughout the organization; there will be significant additions in operations, administration, and engineering. These new personnel make up roughly half of the incremental costs going forward, and their associated costs are estimated to relatively constant. Based on our discussions with ERCOT staff, each employee is estimated to cost approximately $110,000 per year, including salary and benefits.

In addition, the data storage and operational requirements of the nodal market are estimated to be higher than those of the current zonal market, leading to significantly increased costs for hardware and software licenses and support. This cost difference was projected to be $2.8 million in 2011 and $5.9 million in 2012. Hardware and software costs are expected to stabilize at approximately $15.2 million per year in 2012 based on the current design, up from current nodal operational cost of approximately $9.5 million. Based on discussions with ERCOT, we have estimated the average of these incremental increases to be persistent, and the overall incremental increase in operating costs for hardware and software would remain constant at $4.4 million per year.

The numbers presented by ERCOT in its budget of increased costs between 2011 and 2012 do not coincide precisely with these numbers because of the way in which some costs are characterized. Table 17: Summary of ongoing increased incremental TNM operating costs below summarizes which incremental cost increases have been characterized as overall net increases to ERCOT costs in the new nodal market.

Table 17: Summary of ongoing increased incremental TNM operating costs

	Incremental Increase	2011 vs. 2008	2012 vs. 2008	Average difference	Adjusted difference	Notes
Labor & Benefits	Yes	7,542,605	11,886,451	9,714,528	7,285,896	1
Contract Labor - Base Projects	No					2
Contract Labor - Nodal Program	No					2
Support Allocations - Nodal Program	No					2
Backfill Allocations - Nodal Program	No					2
Facilities Allocations - Nodal Program	No					2
Material, Supplies, Tools & Equipment	Yes	90,700	116,215	103,458	103,458	
Special Reviews	No					
Outside Services	Yes	3,376,477	(2,823,690)	276,394	276,394	
Utilities, Maintenance & Facilities	Yes	1,076,830	1,504,813	1,290,822	1,290,822	
HW/SW Renewable License & Maint.	Yes	2,827,924	5,929,620	4,378,772	4,378,772	
Insurance	Yes	(124,631)	(79,998)	(102,314)	(102,314)	
Employee Expenses	Yes	(129,883)	(92,233)	(111,058)	(111,058)	
Interest & Fees	Yes	(2,512)	387,094	192,291	192,291	
NERC Dues	No					3
Other	Yes	1,120,339	757,140	938,740	469,370	4
Property Taxes	Yes	400,000	431,500	415,750	415,750	
	Total	**16,177,849**	**18,016,912**	**17,097,381**	**14,199,379**	

Notes:

1. Based on conversations with ERCOT, ongoing cost has been estimated at 75% of the average difference between 2011 and 2012.

2. These line items in the nodal budget represent primarily changes in the base operating budget resulting from allocations to the TNM program. Based on the CRA/Resero analysis and conversations with ERCOT, they have been excluded from this calculation because they represent no *net* change to ERCOT's *overall* (i.e. TNM + zonal) costs.

3. The large increase in NERC dues in 2011 and 2012 is largely the result of changes in the way that ERCOT participates in NERC processes and programs. These dues would have increased regardless of whether ERCOT was operating a nodal or zonal market, and thus represent no net difference between the operational costs of the TMN and current zonal market.

4. Based on conversation with ERCOT, ongoing miscellaneous costs are estimated to persist at 50% of their average difference between 2011/2012 and 2008.

Interdependent Zonal Costs

In the course of the nodal implementation there are certain costs that ERCOT has incurred that are of use under either market design. These include hardware, software, networking, and infrastructure purchases.

Table 18: Interdependent TNM/Zonal Costs

Project	Total
NMMS	$12,700,000
EMS	$8,900,000
Infrastructure	$18,100,000
Total	$39,700,000

These recent cost estimates were supplied to CRA/Resero by ERCOT. Assuming that the decision facing ERCOT and the Commission is between the options of continuing and halting development, these costs are not relevant because if the TNM is implemented, there is no opportunity to recover these costs without a zonal infrastructure.

Distribution of remaining costs

ERCOT supplied us its monthly expenditure rate and distribution of remaining direct (non-interest) costs. The expenditure rate supplied to by ERCOT did not include a distribution of finance charges, nor did the total summary of yearly costs align with the November 8 budget presentation to the board of directions. This appears to be a consequence of different reports being generated at different times. The following distribution of remaining implementation costs to schedule total implementation costs were assumed.

Table 19: Scheduling of remaining direct and financing costs

	Remaining non-financing costs by year supplied by ERCOT as of 11/14/08	Percentage of total remaining costs incurred per year
2009	$122,049,114	63.6%
2010	$69,270,082	36.1%
2011	$604,365	0.3%
2012		
2013		
2014		

The same time distribution was assumed for remaining implementation costs for market participants' costs.

3.3.2. Market Participants

While ERCOT's TNM implementation costs are the largest contributor to the total cost, market participants' costs are substantial. Estimating of market participants' costs is considerably more complex than estimation of ERCOT's costs. The market contains many different types of entities, from large IOUs to IPPs to small co-ops, and each operates in a relatively unique fashion. The purpose of this CBA update was explicitly not to re-do the 2004 CBA cost estimates, but rather to update and verify costs. CRA/Resero conducted its analysis by interviewing seven different market participants from the following segments: IOUs, munis, co-ops, IPPs and IPMs. Several of the participants we interviewed operate retail operations in Texas, but we were not able to obtain sufficient information from Retail Energy Provider (REP) -only market participants; several were contacted, but did not have detailed nodal implementation data that they could share with us, although their anecdotal comments indicate that their costs are considerably lower than those of market participants who operate ERCOT generation. These REP-only implementation costs have not included in our estimated costs. These market participants spoke to CRA/Resero under a confidentiality agreement that requires divulging neither their identity nor their cost data in anything other than aggregate form.

The market participants interviewed came from a wide spectrum of entities, including some of the largest market participants in ERCOT to multi-state generation fleet owners to small, local companies. Costs varied considerably size of the generation fleet and number of units, but costs were found to be highly dependent upon whether the market participant had prior experience operating in other nodal markets.

Those market participants who operate in other nodal markets such as PJM, or NYISO were able to take considerable advantage of existing equipment and knowledge by re-using systems, re-purposing equipment and leveraging existing institutional knowledge.

After compiling market participant data, and categorizing market participants by number of generation units, amount of capacity in ERCOT and whether they had prior nodal experience, the following estimates were used to extrapolate costs for all market participants.

Table 20: Market participant cost by other-market participation

	Average cost per generation unit	Average cost per MW of installed capacity
No prior Nodal experience group	$673,469	$2,796
Prior Nodal experience	$51,563	$225

The top 20 largest market participants in ERCOT were then used for cost extrapolation as follows:

Table 21: Top market participants used for market participant cost extrapolation

Owner Name	Market Segment	Market Entity	Number of Units	Sum of Capacity
Luminant	IOU	QSE	60	18579
NRG Texas LLC	IPP	QSE	44	14637
FPL Group	IPM	QSE	24	6236
CPS Energy	Muni	QSE	24	5741
Calpine Corp	IPP	QSE	9	4995
Austin Energy	Muni	QSE	18	2591
Lower Colorado River Authority	Co-op	QSE	20	2431
Exelon Generation Co LLC	IPM	QSE	10	2392
American National Power Inc	IREP	QSE	7	1927

Topaz Power Group LLC	IOU	QSE	10	1645
Tenaska Energy	IREP	QSE	2	1370
Brazos Electric Power Coop	Co-op	QSE	9	1315
Midlothian Energy LP	IREP	QSE	4	1156
Guadalupe Power Partners LP	IPP	QSE	2	1142
PSEG Energy	IPM	QSE	2	1135
Navasota Energy	IPP	QSE	4	1100
Tenaska Gateway Partners Ltd	IPP	QSE	1	940
Rio Nogales Power Project LP	IPP	QSE	1	825
Shell Oil Energy	*IPP*	*QSE*	*5*	*332*
Reliant Energy Renewables Inc	IPM	QSE	20	25
Total Nameplate Capacity - Top Companies				70,513
Total ERCOT Nameplate Capacity				96,879

CRA/Resero used the cost ratios detailed earlier in Table 20: to estimate implementation costs for these 20 market participants. Several of the market participants listed above were interviewed; in those cases, actual implementation costs as supplied by those market participants were used.

Estimates of the already-spent implementation costs varied widely, as did estimates of interdependent costs incurred by market participants. Based on the interviews, the average amount of total nodal implementation cost incurred by market participants was 59% of the total costs.

Most market participants interviewed were unable to supply reliable estimates of unwinding and zonal refresh costs, principally because they had not devoted the resources to study this differentiation of costs. In the absence of these data, ERCOT cost ratios were used to estimate this division for the market participants. ERCOT's refresh costs were 24% of its overall system implementation cost ($160 million / $660 million). Using 24% for market participant refresh costs resulted in an estimated unwinding/refresh cost for market participants of $42 million.

The market participants interviewed also provided widely ranging estimates of ongoing incremental operational costs that would result from the TNM implementation. The data supplied were not sufficient to come to a reasonable and consistent estimate of ongoing operational costs, and as a result no market participant incremental TNM operating costs have been included. This has the likely effect of slightly understating the NPV of the market participant implementation costs.

The 20 largest market participants comprise 73% of the installed capacity in ERCOT. After estimating the implementation costs for these market participants, CRA/Resero extrapolated the costs to cover the entire installed capacity base in ERCOT and arrived at the following summary.

Table 22: Summary of market participant (MP) implementation costs, 2008 dollars

Item	Cost	Notes
Estimated TNM implementation costs for top 20 ERCOT MP	$127,728,189	Average of estimates based on number of generation units and capacity
Estimated Costs of all ERCOT MPs	$175,488,535	Extrapolated based on % of capacity owned by Top 20 MPs
Costs incurred so far as a % of total MP costs	59%	Based on sample data reported by the MPs
Estimated costs incurred so far by all ERCOT MPs	$103,500,814	
MP zonal refresh costs	$42,542,675	Based on estimate of 24% of total costs necessary for unwinding
Remaining costs to complete TNM implementation	$71,987,721	
Net cost to continue TNM implementation	$29,445,046	Total remaining costs less refresh and demobilization costs

While very difficult to quantify, many market participants emphasized that the ongoing delays in the nodal market implementation were imposing a cost on them that was greater than if the TNM had been implemented its original schedule. Many market participants, especially those without experience in other nodal markets, have relied upon consultants to provide much of their labor for implementation. While the TNM is delayed, these consultants must often be furloughed or idled while delays are addressed, imposing additional costs.

3.3.3. Glossary of ERCOT budget terminology

The nomenclature for terms associated with the TNM budget can be potentially confusing. The following glossary of terms has been taken from ERCOT, with only minor edits.

- **Internal Labor Costs**
  - Labor costs of ERCOT employees who are working on the Nodal program.
- **External Resource Costs**
  - Includes both contractor and vendor expenses. Examples of the two types of expenses would be contingent labor contracted to work on the Nodal program, and also software development expenses from the software vendors (ABB, AREVA, etc…). Contractor labor is for staff augmentation where ERCOT does not have the number of employees required to perform the additional Nodal project work or where ERCOT does not have employees with the skills to perform the work.
- **Administrative & Employee Expenses**
  - Equipment, tools, office materials & supplies. Also includes ERCOT employee expenses. For example, the expenses for trips by ERCOT employees to vendor sites to supervise software development would fall into this category.
- **Software**
  - Expenses for purchased 3rd party software not being developed solely for the Nodal program. For example, this would include a wide variety of software ranging from Oracle database licenses to Microsoft Windows Server licenses. This cost category also includes the maintenance expenses associated with software licenses.
- **Hardware**
  - Includes all computer hardware purchased to enable the Nodal market and the future maintenance on this equipment. Examples would be servers, data storage hardware and networking equipment.
- **Backfill**
  - This category represents the difference between ERCOT's labor expense for an internal employee and a contractor hired to perform that employee's duties while that employee is working on the Nodal program. For example, if the fully loaded cost to ERCOT for an employee was $50/hr and that

employee was reassigned from ERCOT base operations to the Nodal program and a contractor was hired at $70/hr to perform the base operations duties while the employee is working on the Nodal program, the cost to the Nodal program is the difference between the two expenses, in this case $20/hr.

- **Indirect Support Costs**
  - Several ERCOT administrative departments charge the Nodal program an allocation for services provided to Nodal. For example, ERCOT Procurement, Finance, Legal, and some others provide their services to the Nodal program. The amount charged to the Nodal program is based on an allocation that has been audited and approved.
- **Facilities Allocation**
  - Similar to the Indirect Support Costs category, the Facilities Allocation is a reimbursement to ERCOT base operations from the Nodal program for the facilities space and services provided by ERCOT to the Nodal program.
- **Finance Charge**
  - Interest expenses related to debt incurred to finance the Nodal program.

4. OTHER IMPACT MARKET ASSESSMENT

This section presents the Other Market Impact Assessment (OMIA) update. The OMIA captures potential benefits and costs not otherwise captured in the EIA and IIA. This update reflects new impacts that were not recognized or identified at the time of the original CBA, and other impacts recognized in the 2004 OMIA, but for which the availability of updated information may offer new insights about the nature or degree of the impacts.[21]

A wide range of potential impact areas were examined, and a number were found to be relevant. For those areas deemed relevant, numerous sources of information were relied upon, including:

- Discussions with ERCOT staff;
- Information from Independent Market Monitors (IMMs), including written reports from ERCOT's IMM and the IMMs of other nodal markets;
- Protocol language issued since the 2006 CBA for market monitoring and co-optimization of energy and ancillary services;
- General knowledge about the ERCOT market and its operating environment, including recent significant market events.

The findings of the OMIA update are below. A summary is followed by a more detailed discussion of each area.

4.1. SUMMARY OF OMIA UPDATED FINDINGS

The OMIA update did not identify any substantially new types of impacts, nor did it reveal that the other impacts of a nodal market differ significantly from how they were characterized in the 2004 CBA OMIA. Several of the 2004 OMIA findings were substantiated through the review of updated information and events. At the same time, the updated information suggests that some of the other risks and costs appear to be less significant now than they were at the time of the 2004 OMIA. The 2004 OMIA suggested that were additional net benefits beyond those captured in the quantitative aspects of the CBA. The current OMIA update suggests to an even greater degree that these other impacts are net positive.

Specific insights are summarized below.

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21 The original OMIA applied a rather comprehensive methodology to identify potential other impacts of the nodal market design and operational changes. The scope of the update, however, was more limited. It was not intended to repeat that comprehensive process and instead examined possible drivers (such as the extended implementation schedule and recent market price excursion events) that could change the impacts identified in the original OMIA.

Events and ERCOT's changing environment have identified several Other Market Impact changes: (Discussed in Section 4.2, below.)

1. Given the experience market participants have gained since the 2004 OMIA was prepared, many of the potential risks associated with the nodal market have been largely resolved or mitigated. Although the market is perceived to be more complicated than originally envisioned, market participants have also acquired better understanding through their readiness activities and participation in various stakeholder groups.

2. The value of the nodal market is potentially higher because of the significant deployment of wind generation, given the nodal market's ability to alleviate limitations of ERCOT's current dispatch procedures and provide for rapid system responsiveness.

3. Analysis of ERCOT's summer price excursions by its IMM offers several observations, including that the zonal market may have difficulty in addressing some zonal congestion situations, resulting in high cost impacts, and that nodal markets offer customers more efficiency, choice and flexibility.

Market outcomes from other U.S. nodal markets substantiate the algorithmic and complexity risks identified in the 2004 OMIA. They also suggest that these risks and their impacts decrease over time as market participants and market operators become more aware and take appropriate corrective actions. Similarly, while nodal markets are still not able to capture all of the theoretical benefits of nodal price signals, ongoing refinements of market rules and algorithms are enhancing the benefits of better price signals to be recognized over time. (Discussed in Section 4.3, below.)

Resolution of market monitoring policies suggests that there are reduced nodal market risks associated with price anomalies and market manipulation. The addition of co-optimized ancillary services suggests there may be additional benefits that were not captured in the 2004 CBA. (Discussed in Section 4.4, below.)

4.2. UPDATED OTHER IMPACTS BASED ON CHANGES IN CIRCUMSTANCES AND EVENTS SINCE THE 2004 CBA

CRA/Resero considered the wide variety of circumstantial changes and events that have occurred since the 2004 CBA was conducted in the 2004 timeframe. These include the additional resource build-out that has occurred (especially with respect to wind development), implications of the extended implementation schedule and budget, and the 2008 summer price excursions. For each area reviewed in which potential benefits were suggested, CRA/Resero has updated the assessment of these other costs and benefits where they are distinct from impacts being captured in the updated EIA or IIA.

Complexity: Implications of the extended implementation schedule/budget not captured in the IIA or EIA

The fact that the implementation timeline is longer than initially anticipated influences the costs and benefits identified in the 2004 OMIA. For example, the 2004 OMIA identified the perception that a nodal market has a higher level of complexity that would adversely impact market participants during a limited transition period.

The extended implementation schedule reflects the nodal market's complexity, and based on their involvement in the design and development of the TNM thus far, market participants may judge the nodal market to be even more complex than they would have in 2004. In many respects, however, market participants have already addressed much of the complexity of the nodal market through their involvement in design, development, and training efforts at ERCOT, and through their own readiness efforts. In a sense, they have already progressed through part of that "transition period." As a result, many of the additional costs associated with addressing complexity could be viewed as sunk, and the going-forward incremental impacts on market participants will likely be lower than they were at the time the 2004 CBA was published.

Implications of Wind Expansion

The addition of wind resources in ERCOT increases the importance of the nodal market's telemetry-based 5-minute dispatch, which will replace the existing zonal market's scheduled-based dispatch. For example, the summer 2008 price excursions demonstrated the limitations of ERCOT's current dispatching procedures and the need for rapid system dispatch – a need that should be fulfilled by the ERCOT nodal design.[22]

Implications of Price Excursions:

The price excursions of 2008 offered a number of new insights with respect to limitations of the zonal market design and benefits of the nodal market design.

1. Scarcity pricing effects are much more costly under a zonal market

   While the EIA measures the impact of congestion under normal conditions, Commission and ERCOT policies provide for a form of "scarcity prices" when transmission constraints cannot be resolved. Transmission constraint resolution

[22] See for example, "ERCOT Market Issues" presented to the Texas Industrial Energy Consumers Annual Meeting, by Dan Jones ERCOT IMM, Potomac Economics, July 23, 2008, refers to an event on July 8, 2008 where wind generation picked up and then dropped off by about 1,600 MW over approximately a 60-minute time period. The ramps up and down depleted the Regulation Down and Regulation Up products. With ERCOT's zonal scheduling process, where schedules may be established up to 30 minutes prior to the 15 minute dispatch window, it seems very challenging to manage such significant changes in balancing energy needs.

using shift factors averaged over a zone is much more difficult than constraint resolution using node-specific shift factors. The IMM's analysis of the summer events indicates that "inefficiency of the zonal model has recently produced an unusually high number of constraints that could not be resolved…" and that "…the pricing effects of such irresolvable constraints are much more geographically widespread than would be the case under nodal dispatch and pricing."[23] Under extreme pricing conditions, the application of the scarcity price when transmission constraints cannot be resolved would be much more limited under a nodal market.

2. Nodal markets provide for more customer choice and flexibility

Another implication of the 2008 price excursions was the observation that if prices closely reflect operating conditions and marginal costs, then market participants can be provided with more flexibility in the way they use the transmission system. However, if pricing does not conform to the operating conditions, then substantial operating restrictions must be imposed to preserve system reliability. In this sense, customer flexibility and choice are improved when the nodal market results in efficient and transparent pricing. Conversely, zonal market pricing that does not match the specific system conditions limits market flexibility.[24]

4.3. UPDATED OTHER IMPACTS BASED ON REVIEW OF INDEPENDENT MARKET MONITORING REPORTS FROM OTHER NODAL MARKETS

CRA/Resero reviewed the most current IMM reports[25] and identifies within this section any updated implications with respect to "other" ERCOT nodal costs and benefits.

Generally, in many of the markets, the IMMs observe nodal market benefits, reporting, for example, that the nodal markets "… provide substantial benefits to the region by ensuring that the lowest cost supplies are used to meet demand in the short-term and by establishing transparent, efficient price signals that govern investment and retirement decisions in the long-term."[26]

The IMM reports do, however, generally support the findings of the 2004 OMIA that modeling complexities and algorithmic limitations prevent all of the theoretically possible, short-term

23 Presentation of Dan Jones, ERCOT's IMM, Potomac Economics, to the House Committee on Regulated Industries, June 23, 2008.

24 Id.

25 Updated reports were reviewed from ISO-NE, PJM, MISO, and NYISO.

26 2007 Assessment of the Electricity Markets in New England, page 1. Report available at http://www.iso-ne.com/pubs/spcl_rpts/2007/isone_2007_immu_rpt_fin_6-30-08.pdf.

efficiency gains from being realized and at times also diminish the clarity of the price signals that are intended to produce long-run benefits.

While these are not new findings, the current reports continue to suggest that as nodal markets become more established and as the market operator and market participants gain experience, incremental improvements to the markets lead to corresponding improvements in market efficiency and resultant benefits. Examples of such evidence in the IMM reports include the following:

- In ISO-NE, price signals from the nodal markets were diminished when ISO-NE made supplemental commitments in the Day-Ahead Market to compensate for deficiencies in the specificity of the market algorithms. While ISO-NE has put in place adjustments that are expected to remedy these deficiencies,[27] its experience does provide evidence that nodal market designs require some ongoing adjustments to recognize the theoretical benefits.

- Similarly, ISO-NE's experience with algorithms for setting LMPs offers some evidence that nodal algorithms can initially produce less-than-optimal results and require tuning of the configurations implemented at nodal start up.[28]

- In MISO, constraint relaxation methods that determine how LMPs are calculated when constraints bind (as with too many self-schedules) sometimes produce inefficient results.[29] Also, the practice of separately computing an ex-post price rather than using the ex-ante price derived from the dispatch algorithms leads to inconsistencies between LMPs and generators' dispatch signals.[30]

27 ISO-NE has implemented solutions that include new transmission investment to reduce local reliability commitments; adding local reserve requirements for the forward reserve market and introducing real-time reserve markets that are co-optimized with the energy market; and a forward capacity market that procures capacity on a locational basis. ISO-NE, page 3.

28 For example, nodal market algorithms tend to prohibit certain resources from setting price unless they are dispatched in their flexible range (id. page 11). Additionally, ISO New England's ex post pricing model apparently a) creates a small upward bias in real-time prices in uncongested areas and b) occasionally distorts the value of congestion into constrained areas. (Id., page 12).

29 2007 State of the Market Report for the Midwest ISO, pages ix and 83. Report is available at http://www.midwestiso.org/publish/Document/24743f_11ad9f8f05b_-7b890a48324a/2007%20MISO%20SOM%20Report_Final%20Text.pdf?action=download&_property=Attachment.

30 Id, pages xvi and 55.

- In PJM, the lack of geographic specificity in the scarcity pricing design was found to not provide an effective price signal under scarcity conditions. PJM will be correcting this by adopting a more location-specific scarcity pricing mechanism.[31]

- In the NYISO, improvements to the real-time commitment process have been identified that will help resolve discrepancies that arise between the real-time pricing and the real-time dispatch due to ramping.[32]

- In the NYISO, several historical pricing deficiencies were resolved during this recent reporting period by the implementation of more specificity in the network model.[33]

In at least one instance, the IMM reports suggest that market participants are better able to use nodal transmission rights products to effectively hedge transmission risk as the markets mature, in this case resulting in prices for transmission rights that were more consistent with congestion costs.[34]

In at least one instance the IMM reports also suggest that outcomes of the nodal markets have resulted in transmission system investments and market rule changes that increase the efficiency of the network. For example, in ISO-NE some commitments for local reliability had the effect of diminishing energy and ancillary service prices and increasing uplifts in constrained areas. As a result, ISO-NE implemented solutions that included new transmission investment to reduce local reliability commitments; adding local reserve requirements for the forward reserve market and introducing real-time reserve markets that are co-optimized with the energy market; and a forward capacity market that procures capacity on a locational basis.[35]

In summary, the recent IMM reports substantiate many of the findings of the original OMIA: that because the nodal algorithms are complex and imperfect, at times their results do not

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31 2007 State of the Market Report, pages 6, 111 and 167. Complete report can be found at http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2007-som-volume2.pdf.

32 ”… particularly with respect to real-time scheduling system to better manage ramps at the top of the hour, especially during the morning and evening load changes “, 2007 State of the Market Report, New York ISO, page xi and pages 76-87. Report can be found at http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/NYISO_2007_SOM_Final.pdf.

33 Id. For example, the NYISO implemented a more disaggregated transmission network model for NYC where many lines used to be aggregated. (Pages 68 and 74). Also, better modeling of transmission constraints during periods of high re-dispatch costs to reduce the frequency of price corrections has already been implemented. Pages xiii and 11.

34 Midwest ISO, pages xvi and 88-93.

35 ISO-NE, page 2.

capture all of the potential efficiencies that could be realized from a nodal market. The IMM reports do indicate that, generally speaking, the nodal markets are producing substantial economic benefits through more efficient market outcomes. The reports also suggest that the nodal markets do mature over time and in the process they produce outcomes that more closely approach the theoretical optimum. Further, the IMM reports provide evidence that within the nodal structure market participants take advantage of nodal market information to make investment and operating decisions (e.g., risk management through hedging products) and that the market and system operators use nodal market results to make infrastructure improvements.

4.4. UPDATED OTHER IMPACTS BASED ON REVIEW OF DRAFTED MONITORING AND ANCILLARY SERVICE CO-OPTIMIZATION POLICIES

CRA/Resero reviewed two policies that were not in place at the time of the original CBA: the co-optimization of energy and ancillary services in the nodal market, and policies for market monitoring.

Co-optimization of energy and ancillary services would tend to result in more efficiencies with the nodal market than originally predicted. Although the EIA analysis does assume that spinning reserves are co-optimized with energy, ERCOT's policy to co-optimize the entire suite of ancillary services should result in a higher level of benefits from the nodal market than originally expected as well as benefits beyond those characterized in the OMIA.

With respect to monitoring, effective oversight of nodal markets requires timely access to large amounts of data that includes market results, load forecasts, bids and other inputs. It also requires a variety of sophisticated analytical tools and relevant analytical expertise to sift the data for anomalies and determine root causes. By developing an explicit protocol that places timely market data and appropriate analytical tools at the disposal of both the Independent Market Monitor (IMM) and the PUCT, ERCOT's framework for effective, independent oversight of the TNM should reduce the risks of nodal market price aberrations associated with pricing anomalies and inappropriate behavior.

5. ACKNOWLEDGEMENTS

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We would also like to thank the market participants with whom we spoke, who generously shared their time, insight, and information with us.

APPENDIX A: INPUT ASSUMPTIONS

This appendix summarizes salient inputs to the CRA nodal price forecasting model (GE MAPS) for ERCOT. The analyses simulate the years 2009 to 2012. Primary data sources for the CRA GE MAPS model include FERC submissions by generation and transmission owners (Forms 1, 714 and 715); the NERC Electricity Supply and Demand and Generation Availability databases; data from the US EPA; the Energy Velocity database; and CRA analysis of plant operations and market data. The study also uses data provided by the ERCOT Planning group. Major data components are listed below.

TRANSMISSION

The CRA model is based on load flow cases published by ERCOT in September 2008 for the study time horizon. Monitored constraints include:

- Commercially Significant Constraints (CSC) as defined by ERCOT for 2009. Since definitions of CSC are not available for future years, the 2009 definition is retained, or approximated as closely as possible in case of changes in topology;
- Closely Related Elements (CRE) monitored for their base rating, once again using the current list of elements;
- Contingency constraints that monitor each CRE for the loss of each other CRE related to a given CSC;
- All binding constraints from a UPLAN analysis by ERCOT planning staff for 2009-12;
- Constraints identified by CRA through contingency analysis, using a list of contingencies provided by ERCOT planning staff;
- Non-radial lines loaded above 50% of their base limit in the provided load flows.

LOAD INPUTS

GE MAPS is provided an hourly forecast load for each ERCOT weather zone, as published by ERCOT in November 2008. The weather zones are in turn mapped to the load flow cases, and the load for each weather zone is distributed among the load buses in that zone based on the ratio of loads in the snapshot provided in the load flow case.

ERCOT planning staff also provided a list of locations where load is not time-variant or weather-dependent. CRA modeled load at these buses as constant in each year. Additionally, the weather zone load forecast does not account for approximately 4,900 MW of behind-the-fence load – this was modeled based on levels indicated in the load flow cases.

THERMAL UNIT CHARACTERISTICS

GE MAPS includes a detailed model of thermal generation, in order to accurately simulate operational characteristics, and project realistic hourly dispatch and prices. Modeled characteristics include unit type, unit fuel type, heat rate values and shape (based on unit technology), summer and winter capacities, fixed and variable non-fuel operation and maintenance costs, startup fuel usage, forced and planned outage rates, minimum up and down times, and quick start and spinning reserve capabilities.

The CRA generation database reflects unit-specific data for each unit based on a wide variety of sources. In cases where unit-specific data is not available, representative values based on unit type, fuel, and size are used. Table 23: and Table 24: document these generic assumptions. Note that all costs and prices are shown in real 2007 dollars.

Table 23: Thermal Unit Characteristics

Unit Type & Size	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Minimum Downtime (Hrs)	Minimum Uptime (Hrs)	Heat Rate Blocks
Combined Cycle	$2.50	$21.00	8	6	2 – each 50% @ FLHR
Combustion Turbine <50 MW	$7.00	$15.00	1	1	One block
Combustion Turbine >50 MW	$7.00	$15.00	1	1	One block
Steam Turbine [coal] >200 MW	$3.00	$35.00	12	24	4: 50% @ 1.06% FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] <100 MW	$3.00	$45.00	6	8	
Steam Turbine [coal] <200 MW	$3.00	$35.00	8	8	
Steam Turbine [gas] >200 MW	$3.00	$30.00	8	16	4: 25% @ 118% FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] <100 MW	$5.00	$34.00	6	10	
Steam Turbine [gas] <200 MW	$4.00	$30.00	6	10	
Steam Turbine [oil] >200 MW	$3.00	$30.00	8	16	
Steam Turbine [oil] <100 MW	$5.00	$34.00	6	10	
Steam Turbine [oil] <200 MW	$4.00	$30.00	6	10	

Table 24: Thermal Unit Characteristics

Unit Type & Size	Quick Start (%)	Spinning Reserve (%)	Forced Outage (%)	Planned Outage (%)	Typical Outage Length (Days)
Combined Cycle	-	20%	1.81	7.40	3
Combustion Turbine <50 MW	100%	0%	2.81	5.28	1
Combustion Turbine >50 MW	100%	0%	2.60	6.94	1
Steam Turbine [coal] >200 MW	-	20%	3.07	9.10	7
Steam Turbine [coal] <100 MW	-	20%	3.78	8.32	3
Steam Turbine [coal] <200 MW	-	20%	4.57	9.43	3
Steam Turbine [gas] >200 MW	-	20%	3.50	14.11	7
Steam Turbine [gas] <100 MW	-	20%	2.62	6.81	2
Steam Turbine [gas] <200 MW	-	20%	3.23	11.11	2
Steam Turbine [oil] >200 MW	-	20%	2.79	13.51	7
Steam Turbine [oil] <100 MW	-	20%	1.46	8.33	2
Steam Turbine [oil] <200 MW	-	20%	3.01	12.16	2

The list of generators, installation and retirement dates, and summer and winter capacities are drawn from the 2008 edition of the Capacity, Demand and Reserves (CDR) report published by ERCOT. The primary data sources for other unit characteristics are the NERC Electricity, Supply and Demand (ES&D) 2006 database, and the Energy Velocity database. Heat rate data is drawn from prior ES&D databases where available. For newer plants, heat rates are based on industry averages for the technology of the unit. The NERC Generation Availability Data System (GADS) 2003 database, released January 2005, is the source for forced and planned outage rates, based on plant type, size, and vintage. Fixed and variable operation and maintenance costs are estimates based on plant size, technology, and age. These estimates are supplemented by FERC Form 1 submissions where available.

Plants that are known to be cogeneration facilities are either modeled with a low heat rate (6000 Btu/kWh), or set as must-run units in the dispatch, to reflect the fact that steam demand requires operation of the plant even when uneconomical in the electricity market.

NUCLEAR UNITS

The study assumes that the South Texas and Comanche Peak plants run at full capacity when available, and that they have minimum up and down times of one week. Nuclear plants do not contribute to reserves. The model includes refueling and maintenance outages for each nuclear plant. In the near future, outages posted on the NRC website or announced in the trade press are included. For later years, refueling outages are projected on the basis of the refueling cycle, typical outage length, and last known outage dates of each plant. Since these facilities are treated as must run units, CRA does not specifically model their cost structure. The Comanche Peak 2 unit is up-rated by 37 MW in the course of the 2009 & 2010 refueling outages, as approved by the Nuclear Regulatory Commission.

Hydro Units

GE MAPS has special provisions for modeling hydro units, and requires specification of a monthly pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. CRA assumes that the monthly maximum capacity is equal to the installed capacity, that the minimum capacity is zero (i.e. there are no stream flow regulations), and that the capacity factor is 17%. Plants are allowed to provide spinning reserves up to 50% of name plate capacity.

Renewable Resources

There is a substantial amount of wind generation online in ERCOT, as well as several farms in development or under construction. In consultation with ERCOT staff, CRA developed a list of new wind farms that were included in this study – these are summarized in Table 25. The Renewable Energy Credit (REC) market is not modeled, since it does not impact daily dispatch of the wind units.

ERCOT planning staff provided CRA with annual hourly wind profiles for each wind farm, originally developed in the Competitive Renewable Energy Zones (CREZ) process. These schedules were imposed for each year in this study.

Table 25: Wind Farms in Development

Farm	Zone	Capacity	Online
Post Oak Wind	W	200	11/2008
Goat Wind	W	70	1/2009
Penascal	S	202	1/2009
Gulf Wind 1	S	283	1/2009
Coyote Run	W	205	6/2009

Capacity Additions and Retirements

CRA includes new generation based on projects in development or in the permitting process, as indicated by trade press announcements, trade publications, environmental permit applications, and internal knowledge. In this study the list of thermal new entry was developed from the CDR report and in consultation with the ERCOT planning group. Table 26 lists new thermal units.

Since the study time horizon extends to 2012, CRA did not add any speculative new entry, or evaluate the economics of returning mothballed generation to service.

CRA tracks planned and announced retirements from power pool publications and trade press announcements. In this study, CRA retired the Leon Creek 3 unit, at the end of 2009.

Table 26: Thermal Unit Additions

Unit	Type	Size	Online
Bosque Expansion	CC	255	03/2009
Sandow 5	Coal	581	06/2009
Winchester Peaking	GT	178	06/2009
Laredo Peaking 4 & 5	GT	193	07/2009
Oak Grove 1	Coal	855	07/2009
Cedar Bayou 4	CC	544	08/2009
Barney M Davis	CC	538	11/2009
Nueces Bay	CC	538	11/2009
J K Spruce 2	Coal	750	07/2010
Oak Grove 2	Coal	855	07/2010
Jack County 2	CC	600	06/2011
Sandy Creek 1	Coal	800	06/2012

Environmental Regulations

CRA models NOx and SO_2 emission rates for all units where such data is available in either US Environmental Protection Agency (EPA) databases, or Energy Velocity. Variable operating and maintenance cost increases associated with the installation of scrubbers or selective catalytic reduction devices (SCRs) on existing plants are included in the marginal cost estimation where data is available. Data on retrofits is drawn from Energy Velocity.

In addition, CRA models compliance with various allowance trading programs. Per the EPA Acid Rain program, the cost of SO_2 allowances are included in the marginal cost of units – allowance prices are drawn from Cantor Fitzgerald and Evolution Markets environmental brokerage services.

CRA also includes allowance prices for the regional NOx programs in the Houston – Galveston area. In the Dallas – Fort Worth area, older units without NOx retrofits are retired, based on a list provided by ERCOT staff.

Given the regulatory uncertainty and the time frame of this analysis, CRA did not model either mercury or carbon emissions programs.

External Region Supply

ERCOT is connected to the Southwest Power Pool (SPP) via DC ties at Oklaunion and Monticello, and to the Mexican electric system via DC ties at Eagle Pass & McAllen, and a variable frequency transformer at Laredo. In this study, the North and East DC ties are modeled as importing power into ERCOT based on a schedule provided by ERCOT planning staff. The ties to Mexico are assumed not to run.

Market Model Assumptions

A. Marginal Cost Bidding: All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel VOM plus opportunity cost of tradable permits). To the extent that real markets are not perfectly competitive, the model tends to underestimate prices.

B. Operating Reserves: Based on discussion with ERCOT staff, spinning reserves are modeled at 1,600 MW in all hours. This simulates both true spinning reserve, and an allowance for regulation reserves. Quick start reserves are not modeled. As described above, thermal units are allowed to provide spinning reserves up to a maximum of 20% of their capacity.

C. Marginal transmission Losses: GE MAPS has the capability of simulating marginal losses and their impact on nodal energy prices. However, CRA conducted this study by modeling transmission losses at average rates.

Fuel Prices

Natural gas and fuel oil price forecasts are based on the 2008 release of the Annual Energy Outlook (AEO), published by the Energy Information Administration. CRA forecasts spot gas prices at multiple points in the system, based on historical differentials between these points and associated hubs. The Henry Hub forecast is drawn from the AEO and presented graphically on Figure 1 which depicts historical prices, AEO forecast and NYMEX futures as traded on December 5, 2008. NYMEX prices are added for comparison purposes.

Similarly fuel oil prices are developed on a regional basis, starting with data in the AEO.

A number of generators can utilize a secondary fuel type. This possibility is simulated as follows:

- Natural Gas Primary: Units that primarily burn natural gas typically face stringent restrictions on the fraction of time that they may burn fuel oil. CRA makes the assumption that each unit is allowed to switch to fuel oil for the one month in each year in which the gas prices are highest.
- Fuel Oil Primary: Units that primarily burn oil may switch to gas whenever it is economically justified, with a heat rate degradation of 3%. Thus, the fuel type is switched between whenever the price of natural gas plus 3% is less than the price of the appropriate fuel oil (FO2 or FO6).

Coal prices are estimated per coal plant, based on 2008 actual coal purchase prices as published in Energy Velocity.

Nuclear plants are assumed to run whenever available, so nuclear fuel prices do not impact commitment and dispatch decisions in the market simulation model. CRA therefore does not do a detailed analysis of nuclear fuel prices.

Figure 12: Natural Gas Price Forecast and History. Henry Hub (real 2007 $/MMbtu)