DRAFT

MEMORANDUM

TO: ERCOT Cost-Benefit Concept Group

FROM: Prashant Murti, Ellen Wolfe, and Alex Rudkevich, Tabors Caramanis & Associates

RE: Draft Input Assumptions and Methodology for GE-MAPS price forecasting model

DATE: April 22, 2004

This memorandum summarizes salient inputs to the TCA locational price-forecasting model (GE-MAPS) for the ERCOT region. TCA has compiled a database for the ERCOT system based on public domain data sources including various FERC forms (Form 1, 714, 715), the EIA 411, the NERC ES&D and GADS databases, data from the US EPA, various trade press announcements, and the ERCOT planning data. TCA has included in-house analysis to ensure data integrity and validity and to ensure consistency of plant operations with market developments.

The major data components and the associated data sources are described as indicated below.

Please note that additional requirements for information from ERCOT are detailed at the ends of the descriptions of Items 1, 2, 4, 5, 6, 8, and 10, and at three places in the description of Item 12.

Item **Page**

1. Load Inputs

***Description**:* GE-MAPS requires an hourly load shape and a forecast of annual peak load and total energy for each load serving entity or zone. TCA will receive load forecasts by TDSP. TCA will model load by TDSP/Zone[1] sub-entities: that is, demand in each zone will be represented by TDSP, and for each TDSP, demand will be represented by zone if the TDSP serves load in more than one Zone. The critical inputs for GE MAPS are 1) historical hourly loads for one year for each configuration; 2) forecast of annual total energy for each entity and 3) forecast of non-coincident peak demand for each entity.

TCA will generate loads for modeling based on the following process.

- TCA will start with historical hourly load shapes by Zone and will use a Summer Peak Load flow case for the same historical period to ascertain the fraction of the load in each Zone attributed to each TDSP. TCA will apply these fractions to derive the hourly load shape by Zone by TDSP;
- TCA will use Summer Peak load flow files for 2005–2009 to derive a coincident peak demand forecast by TDSP/Zone. For the historical period in which both coincident and non-coincident peaks are available, TCA will estimate the non-coincident to coincident ratios by Zone and will apply those ratios for each entity within the corresponding zone to derive a forecast of non-coincident peak demand levels;
- TCA will use the forecast annual energy by TDSP, and load flow files for 2005–2009, to ascertain future distribution of each TDSP annual energy between Zones, and thereby derive the annual energy forecast by TDSP/Zone;
- TCA will analyze rates of growth for non-coincident peak and annual energy by TDSP/Zone for 2004–2009 based on the available forecast data. Based on this analysis, TCA will project growth rates for non-coincident peak and annual energy for each configuration in order to extend peak and energy forecasts beyond 2009. TCA will explore options for developing load growth patterns by zone or more detailed regions/locations.

In the process described above, TCA will make a distinction between net load reported in the FERC 714 forecast and Self-Served load and other Flat load (such as oil pumping stations and process industry loads) embedded in solved load flow cases. Self-Served and Flat load will be modeled directly in GE MAPS. ERCOT's publicly posted dictionary will provide necessary information to identify buses with Self-Served load. The level of the Self-Served/Flat load at each bus will be determined based on the information provided in the load flow cases. TCA will assume a fixed hourly pattern in each year for each such bus TCA will use the ownership and geographical information in load flow files and in ERCOT's data dictionary to attribute impacts (such as pricing changes) to regions and market segments as part of TCA's post-processing activities.

***Data Sources**:* ERCOT has provided or will provide the following data sources based on recently updated (April 2004) forecasting efforts. TCA will extrapolate the data obtained from ERCOT to develop peak and energy forecasts for any remaining study years.

---

[1] For the Base Case, to represent the North East zone and the Northern zone, TCA will use the 2003 load zone shape for the Northern Zones, given that a complete year of historical load data does not exist for the 2004 zonal configuration. In other words, although it is recognized that the load of the Northeast zone and the new Northern zone most likely exhibit different hourly behavior across the year, the hourly load shape for the Northeast zone and the Northern zone are assumed to be identical for purposes of the study.

2. Thermal Unit Characteristics

***Description**:* GE-MAPS models generation units in detail in order to accurately simulate operational characteristics and thereby predict realistic hourly dispatch and prices. The characteristics modeled are the following:

- Unit type (steam cycle, combined-cycle, simple cycle, cogeneration, etc.)
- Heat rate values and curve (developed on the basis of unit technology)
- Summer and winter capacity
- Variable operation and maintenance costs
- Fixed operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick-start and spinning reserves capabilities
- Startup costs

TCA's generation database reflects unit-specific data for each generating unit based on a variety of sources as referenced below. ERCOT staff will review the unit-specific data against data they have internally. Units for which ERCOT identifies any significant discrepancies will be identified to TCA, at which time TCA and the CBCG will develop a plan for further validating and updating the data for those units.

In the event unit-specific data has not been available to TCA, representative values based on unit type, fuel, and size are used. Table 1 and Table 2 document these generic assumptions[2]. Note that all prices are in real 2003 dollars. The analysis employs real dollars through the simulation. The resulting prices can be inflated if necessary.

Cogeneration Plants will be modeled as follows: TCA will use a low heat rate (6000 Btu/kWh) in the dispatch to reflect the fact that cogeneration plants generally have a steam demand that requires operation of the plant. ERCOT staff has identified units that supply self-served loads, and that have historically been represented with static load shapes. For these units, TCA will schedule their output incorporating these flat energy values across the hours. Units that have not traditionally been designated as self-serve units (by the TDSPs or ERCOT) will be represented by using the thermal characteristics as described in the balance of this section.

***Data Sources**:* The primary data source for generation units and characteristics is the NERC Electricity, Supply and Demand (ES&D) 2003 database, which contains unit type, fuel type (primary and secondary), and capacity data for existing units. 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) 2002 database 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. The FOM values include an estimate of $1.50/kW-yr for insurance and 10% of base FOM (before insurance) for capital improvements.

---

[2] Note that certain data types are specified on a plant-specific basis in TCA's data base and therefore do not have corresponding generic data. These include full load heat rates and emissions data.

DRAFT

Table 1: Characteristics for Generic Thermal Units

Unit Type & Size	FOM ($/kW-yr)	VOM ($/MWh)	Minimum Downtime (hrs)	Minimum Uptime (hrs)	Heat Rate Shape
Combined Cycle	18.00	3.00	6	6	2 blocks, each 50%@FLHR
Combustion Turbine <100 MW	7.00	7.00	1	1	One block
Combustion Turbine >100 MW	7.00	3.50	1	1	One block
Steam Turbine [coal] <100 MW	38.00	2.00	6	8	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] <200 MW	35.00	2.00	8	8	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] >200 MW	35.00	1.00	12	24	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [gas] <100 MW	38.00	8.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] <200 MW	35.00	6.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] >200 MW	16.00	4.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] <100 MW	38.00	8.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] <200 MW	35.00	6.00	6	10	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] >200 MW	16.00	4.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%

Table 2: Characteristics for Generic Thermal Units

Unit Type & Size	Quick Start Capability (% of Capacity)	Spinning Reserves (% of Capacity)	Forced Outage Rate (% of Year)	Planned Outage Rate (% of Year)	Total Unavailability (% of Year)	Startup (MMBtu /MW)
Combined Cycle	0.00	10.00	1.50	6.82	8.32	1.00
Combustion Turbine <100 MW	100.00	30.00	4.34	5.21	9.55	0.00
Combustion Turbine >100 MW	100.00	30.00	2.53	7.50	10.03	0.00
Steam Turbine [coal] <100 MW	0.00	10.00	2.96	9.48	12.44	
Steam Turbine [coal] <200 MW	0.00	10.00	3.46	8.66	12.12	20.00
Steam Turbine [coal] >200 MW	0.00	10.00	4.51	9.79	14.30	
Steam Turbine [gas] <100 MW	0.00	10.00	3.09	7.27	10.36	
Steam Turbine [gas] <200 MW	0.00	10.00	3.69	10.50	14.19	10.00
Steam Turbine [gas] >200 MW	0.00	10.00	3.38	12.46	15.84	
Steam Turbine [oil] <100 MW	0.00	10.00	2.14	7.91	10.05	
Steam Turbine [oil] <200 MW	0.00	10.00	4.64	10.95	15.59	
Steam Turbine [oil] >200 MW	0.00	10.00	4.01	12.04	16.05	10.00

3. Nuclear Units

***Description**:* The South Texas and Comanche Peak plants are assumed to be online throughout the study. TCA assumes that all nuclear plants run when available and that they have minimum up and down times of one week. Forced outage rates are drawn from the Energy Central database of unit outages, for each nuclear unit. These plants do not contribute to quick-start or spinning reserves. Refueling and maintenance outages for each nuclear plant are also simulated. Outages posted on the NRC website or announced in the trade press for the near future 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, TCA does not specifically model their cost structure.

***Data Sources**:* NRC publications and trade press announcements, Energy Central database.

4. Hydro Units

Description: GE-MAPS has special provisions for modeling hydro units. For conventional or pondage hydro units, TCA specifies a pattern of water flow, i.e., a minimum and maximum generating capability and the total energy for each plant. TCA assumes that hydro plants can provide spinning reserves of up to 50% of plant capacity. In this analysis, TCA assumes that the maximum capacity of each plant is flat throughout the year and that the minimum capacity is zero, i.e., that there are no stream-flow or other constraints that force a plant to generate. TCA uses a monthly capacity factor of 17% to arrive at the total energy for each plant.

***Data Sources**:* The list of hydro units and their maximum generating capacities is taken from the NERC ES&D database for 2003. The monthly capacity factor is a TCA assumption. TCA will use LCRA-specific hourly hyrdo schedules as available.

5. Renewable Resources

Description: Renewable resources, such as wind, solar, and geothermal, are given special attention in the modeling. TCA has four options for modeling these resources:

1. As thermal units with higher outage rates.
2. As thermal units for which the higher outage rates are specified on a weekly, monthly, or quarterly basis.
3. As fixed hourly schedules.
4. As pondage modifiers (see Section 4, above), with fixed monthly or annual energy.

In particular, there is a substantial amount of wind capacity in ERCOT. For this capacity, TCA will model wind resources using specific monthly or seasonal when available and will otherwise use methods employed by ERCOT planning studies to model the wind resources, including using an annual capacity factor of 20% for each unit. The capacity factor can be varied seasonally if appropriate data is available. Wind units do not contribute to the operating reserves markets. Per data provided by the CBCG, only 10% of their capacity would count towards installed capacity calculations.

Renewable resources in ERCOT are issued Renewable Energy Credits (REC), and retail electric providers (REP) need to hold sufficient numbers of these allowances, giving rise to a market for RECs. TCA will assume that this market does not affect the dispatch of renewable resources, since the renewable resources are predominantly wind units, which will tend to run when available. TCA will attempt to obtain data on market prices for RECs, and incorporate any data obtained in revenue calculations for renewable resources and REPs.

.

6. Capacity Additions and Retirements

Description: New entry through 2007 is based on existing projects in development or on projects in advanced stages of permitting, as indicated by trade press announcements, environmental permit applications, and data published by ERCOT. After 2007, in addition to known projects, capacity is added on the basis of economic criteria and market conditions.

New capacity is likely to be either combined-cycle gas turbines (CCGT), simple-cycle gas turbines (SCGT), or coal-fired steam turbine (STc) plants, depending on market requirements and the relative economics of these options.[3] Table 3 shows the capital cost, performance, and financing assumptions TCA uses for new entry. Using the TCA financial model, the values in Table 3 indicate annual carrying charges for new SCGT, CCGT, and STc units to be about \$84/kW-yr, \$112/kW-yr, and \$235/kW-yr respectively (in real 2003 dollars). This means that a capacity price can reach \$94/kW-yr (\$75/kW-yr Carrying Charge + \$10/kW-yr FOM) during capacity shortage years.

Table 3: Financing Assumptions

Cost Component	CCGT	SCGT	STc	Notes
All-In Capital Cost (\$/kW)	600-700	350-450	2000	
Debt: Equity Ratio	45:55	40:60	50:50	
Return on Equity	16%	19%	12%	
Cost of Debt	8%	8%	8%	
Term of Debt	20 years	20 years	30 years	Our model uses weighted average cost of capital
Fixed O&M (\$/kW-yr)	15	5	25	
Variable O&M (\$/MWh)	2.0	3.5	1.0	
Full Load Heat Rate (Btu/kWh)	6,900	10,000	9,000	Used for future economic entry. Announced entry is assigned a heat rate based on installed technology.
Forced Outage Rate	3%	4%	4%	
Planned Outage Rate	4%	3%	9%	

TCA also will assume a variation in carrying charges based on estimated increased costs of development in ERCOT's major metropolitan areas. For the Dallas-Ft. Worth and Houston-Galveston areas, TCA will use a multiplier of 1.25 to the carrying charge for economic new entry, consistent with an assumption TCA uses in modeling other major metropolitan areas in the United States.

As part of the economic addition model, TCA will consider the economic viability of making mothballed plants re-operational. Based on industry experience, TCA estimates an additional hurdle of \$4/kW for a combined cycle plant, and \$6/kW for a gas- or oil-fired steam turbine plant, if reintroduced within two years after being mothballed. After two years, these numbers will be escalated at 20% per year. These hurdles represent the costs of re-introducing the plant, and are in addition to any fixed and variable O&M costs that the plant would need to recover. Values for coal-fired plants would be much higher, but there are currently no coal plants scheduled to be mothballed in ERCOT. Table 4 lists mothballed plants per data provided by the CBCG (currently being updated by input from ERCOT staff).

[3] Some market participants have identified the fact that there is some incentive in the ERCOT region to develop coal resources for purposes of fuel diversification. TCA will include these incentives in its economic addition model as specified by the CBCG. In lieu of further specification, TCA's model will be based simply on the ongoing costs and market profitability of coal units relative to alternatives.

Table 4: Mothballed Units (to be updated)

Unit	County	Zone	Type	MW
Abilene 4	Taylor	West	STgo	18.0
E S Joslin 1	Calhoun	South	STgo	254.0
Hays Energy Facility 1-4	Hays	South	CCg	989.0
Lake Pauline 1-2	Hardeman	West	STgo	35.0
Lon C. Hill 1-4	Nueces	South	STg	559.0
Nueces Bay 5-7	Nueces	South	STgo	560.0
Oak Creek 1	Coke	West	STgo	85.0
P H Robinson 1-4	Galveston	Houston	STg	2265.0
Paint Creek 1-4	Haskell	West	STgo	217.0
Rio Pecos 4A-5	Crockett	West	CCgo	42.0
Rio Pecos 6	Crockett	West	STgo	98.0
Victoria 4-6	Victoria	South	STgo	491.0

Outside of the financial model, TCA will add resources across the study years to satisfy regional renewable resource requirements as specified by the Texas PUC. TCA will introduce a total of 2,000 MW of wind resources between 2000 and 2009, of which 1,825 MW is either operational or in development. The remaining resources will be sited based on the recommendation of ERCOT staff. There are no additional requirements beyond the year 2009 established at this time. Table 5 shows announced wind resources and the locations for wind development. TCA and the CBCG will explore with ERCOT wind developers further wind additions beyond the year 2009.

Table 5: Wind Generation

Project/Location	County	Zone	Install Date	Size (MW)
Existing wind plants (post 1999)	Various	West	2001-2003	1027.8
Silverstar	Eastland	West	May 2004	225.0
Sweetwater Wind 2	Nolan	West	May 2005	400.0
Culberson County Wind 1	Culberson	West	May 2006	175.0
Near McCamey	Upton	West	Jan 2008	100.0
Near San Angelo	Runnels	West	Jan 2009	75.0
Total 2001-2009				**2002.8**

Reliability Must Run (RMR) units will be treated as part of the economic addition and retirement model for the Change Case. For the Base Case, it is assumed that RMR units will be kept operational until any date that such units are no longer needed for RMR as specified by ERCOT staff and will continue to require contract payments, given that local congestion payments are based solely on marginal operating costs and that insufficient market signals are available to entice new generation development to provide local congestion management. In the event RMR units are no longer needed, such units will be mothballed or retired based on ERCOT staff input. In the Change Case, however, when locational price signals are available, TCA will assume that all congestion management will be market based, and that if any existing RMR resources are uneconomical with solely LMP payments, they will be retired. When locational prices become high enough, new resource development will occur to resolve transmission constraints. TCA will report on the profitability of each RMR unit in each case, providing a metric of the RMR contract payments allocated to market participants. Table 6 lists plants that TCA will treat as RMR units in the Base Case[4].

[4] Rio Pecos 6 is listed as an RMR unit, but is also mothballed, so TCA will not include it in the RMR analysis.

Any RMR units as identified by ERCOT staff needed during the study period for voltage or stability purposes will remain as RMR units as needed in both the Base Case and the Change Cases, regardless of the unit's profitability as determined in the simulations.

Table 6: RMR Units (to be updated)

Unit	County	Zone	Type	MW
B M Davis 1-2	Nueces	South	STgo	697.0
J L Bates 1-2	Hidalgo	South	STgo	182.0
Frontera 1	Hidalgo	South	CCg	150.0
Ft Phantom 2	Jones	West	STgo	204.0
La Palma 4-6	Cameron	South	STg	201.0
La Palma 7	Cameron	South	GTg	52.0
Laredo 1-3	Webb	South	STgo	178.0
San Angelo 1-2	Tom Green	West	CCgo	123.0

In addition to the special cases described above, TCA tracks planned and announced retirements published by ERCOT or in trade press announcements. TCA monitors the profitability of units for every model run and retires units that are not profitable, on the basis of their performance in the model and on external judgment about the likelihood of those plants improving profitability in later years. Announced thermal unit new entry is shown in Table 7, based on units that have obtained interconnection agreements with ERCOT. The CBCG is considering including muni and co-op announced additions in addition to other units that have obtained signed interconnection agreements. Anticipated retirements are shown in Table 8. A capacity balance for ERCOT, prior to economic entry and retirements, is shown in Table 9. The capacity balance should be treated as preliminary, pending reconciliation of the TCA generator database with the ERCOT data dictionary or other data sources provided by the CBCG.

Data Sources: ERCOT reports and website publications, trade press announcements. Wind additions are based on discussion with ERCOT staff.

Table 7: New entry (to be updated)

Unit Name	County	Zone	Type	Installation	Capacity (MW)	Heat Rate
Boonsville 1-3	Jack	North	CCg	May-2006	620	7,000
Silas Ray 10	Cameron	South	GTg	Dec-2004	45	10,000

Table 8: Anticipated retirements

Unit Name	County	Zone	Type	Retired	Capacity (MW)
C.E. Newman 1-4	Dallas	North	STgo	Dec-04	51.0
Holly Street 1-2	Travis	South	STgo	Dec-04	200.0
South Houston Green Power 1-6,10	Galveston	Houston		Dec-04	91.0
Spencer 3	Denton	North	STgo	Dec-04	27.0
Leon Creek 3	Bexar	South	STgo	Oct-08	65.0
Holly Street 3-4	Travis	South	STgo	Oct-09	391.0
Powerlane Plant 1-3	Hunt	North	STgo	Dec-10	88.1

Table 9: Preliminary ERCOT Capacity Balance (MW) (to be updated when data set is complete)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total Internal Demand	61,432	62,906	64,416	65,962	67,545	69,166	70,826	72,526	74,266	76,049	77,874
Interruptible Demand	1,401	1,401	1,401	1,401	1,401	1,401	1,401	1,401	1,401	1,401	1,401
Net Internal Demand	60,031	61,505	63,015	64,561	66,144	67,765	69,425	71,125	72,865	74,648	76,473
Purchases	111	111	112	112	113	113	114	114	115	115	115
Sales	189	189	189	189	189	189	189	189	189	189	189
New Entry	2,302	525	0	0	100	75	0	0	0	0	0
Retirement	0	268	0	0	0	65	379	89	0	0	0
Installed Capacity	80,751	79,583	79,315	79,315	79,415	79,490	79,425	79,046	78,957	78,957	78,957
Reserve Margin %	34%	29%	26%	23%	20%	17%	14%	11%	8%	6%	3%

7. Fuel Price Forecasts

***Description**:* GE-MAPS takes as input the monthly fuel price for each plant. The fundamental assumption of behavior in competitive energy markets is that generators will bid their marginal cost into the energy market. The marginal cost is the opportunity cost of fuel purchased (in addition to variable O&M and environmental adders), or the spot price of gas at the location closest to the plant. TCA therefore uses forecasts of spot prices at regional hubs, and further refines these on the basis of historical differentials between price points and their associated hubs. For oil and coal, TCA uses estimates of the price delivered to generators on a regional basis.

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 may burn fuel oil at most in one month of the year. Because gas prices are typically highest in January, the model allows the unit to switch to fuel oil for January if the oil price at that location is lower than the natural gas price.

- Fuel Oil Primary: Units that primarily burn oil may switch to gas whenever it is economically justified. TCA assumes that natural gas shortages prevent this from happening in winter (November though March). A heat rate degradation of 3% is modeled when the unit switches to natural gas. Thus, the fuel type is switched from April through October, whenever the price of natural gas plus 3% is less than the price of fuel oil.

Coal prices are drawn from a database provided by RDI, which forecasts delivered coal prices, including transportation and handling, for each major coal plant in the United States. If any coal-fired new entry were added, TCA proposes a coal price of $1.15/MMBtu, staying flat in real terms.

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

A more detailed analysis of the TCA oil and gas price forecasts will be provided in a separate memorandum.

8. Transmission System Representation

Description*:* The TCA model includes the entire ERCOT transmission system—transformers, lines, phase shifters, and buses. Underlying the model is a solved load flow case provided by ERCOT. Potentially binding lines, interfaces, and contingency constraints are monitored. Where constraints are based on thermal ratings, the limits are drawn from the load flow. TCA will model monthly or season ratings for those lines and ratings specified by ERCOT staff, based on the dynamic rating pilot program and prospective analysis related to other lines. For interfaces or constraints that are limited by voltage or stability or other considerations, limits are implemented as specified by ERCOT. Voltage and stability constraints will only be monitored if suggested by ERCOT. TCA will model constraints published by ERCOT for the transmission system above 69kV level. For the 69kV system, TCA will monitor only those constraints that ERCOT identifies as being likely to bind.

TCA will account for load switching by relaxing the single contingency constraints on alternative lines connected to switchable loads, as identified by ERCOT staff. TCA has only received data on the Centerpoint (Houston) load throwover, and will require additional input from ERCOT staff for the implementation of this data[5].

TCA will further assume that Special Protection Schemes (SPS), as described in ERCOT documents provided to TCA, are effective at managing their respective constraints. As part of this assumption, TCA will relax those constraints that the SPS are designed to manage. Table 10 shows a summary of the SPS for which TCA has received input.

[5] TCA is currently investigating the treatment of the large number of bus numbers provided by ERCOT staff, but will seek clarification from Staff prior to implementation in the modeling processes.

Table 10: SPS Data

SPS	Monitored Element(s)	Contingencies	Impacted Generators
Kendall (LCRA)[6]	Kendall 345kV-138kV Transformer	Loss of Hays Energy-Zorn 345kV Dual + Hays Energy generation > 336 MVA	Hays Energy
Valley (ONCOR)	Valley-Anna Switch 345kV Valley-Farmersville 345kV	Various	Kiamichi Valley Unit 3
Marion 1 (LCRA)	Marion-GPI Switch 138kV	Marion-Zorn 345kV Dual + Marion-Clear Springs 345kV Dual	GPP
Marion 2 (LCRA)	Marion-GPI Switch 138kV	Marion-Zorn 345kV Dual + Clear Springs-Zorn 345kV Dual	GPP Rio Nogales
Monticello 1 (ONCOR)	Cascading instabilities (?)	Farmersville 345kV-Monticello switchyard	Monticello
Monticello 2 (ONCOR)	Monticello-Sulphur Springs 345kV	Monticello-Farmersville 345kV Dual + Monticello-Allen 345kV	Monticello
Monticello 3 (ONCOR)	Monticello-Allen 345kV	Monticello-Farmersville 345kV Dual + Monticello-Sulphur Springs 345kV	Monticello
Paris 1 (ONCOR)	Paris Switch-Valley 138kV	Paris Switch-Valley 345kV	Lamar
Paris 2 (ONCOR)	Paris Switch-Valley 345kV	Monticello-Allen 345kV + Monticello-Sulphur Springs 345kV	Lamar
Mt. Enterprise (ONCOR)	Tenaska Gateway unit instability	Mt Enterprise-Martin Lake-Trinidad 345kV Dual	Tenaska Gateway
Ennis West (ONCOR)	Ennis West-Ennis 138kV Ennis West-Sterrett 138kV	Various	Tractebel Ennis
Roanoke (ONCOR)	Roanoke 345kV-138kV Transformer	Roanoke-West Denton-Northwest Carrolton 345kV Dual	West Texas
Eskota (ONCOR)	Eskota-South Abilene 138kV	Various	Trent Wind Farm
Venus (ONCOR)	All circuits terminating at Venus and Everman	Various	Midlothian Energy
Northeast SPS	[to be determined]		

TCA will incorporate transmission upgrades that are announced or planned for the study period, and the corresponding changes in interface or constraint limits, provided such data is supplied by ERCOT.

Data Sources*:* TCA will use load flows as provided by ERCOT and will monitor constraints and interfaces suggested by ERCOT. For Special Protection Schemes ERCOT posted SPS documents and other ERCOT staff discussion documents will be used.

[6] The Hays plant has been mothballed, which should render this SPS irrelevant unless the plant is restored to service.

9. Environmental Regulations

Description*:* NO_x and SO_2 emission rates for power plants in Texas are obtained from the EPA Clean Air Markets database. This data is currently available for 2002; 2003 data should be published soon. TCA will use the most recent data available at the time of modeling.

Variable operating and maintenance costs associated with installed scrubbers (SO_2 reduction) or with Selective Catalytic Reduction (SCR) processes for NO_x reduction are included in the model runs. TCA adds these environmental operating and maintenance values to create the marginal cost bids for applicable units. TCA does not include any fixed or capital cost of these emission control technologies in the calculation of marginal cost. TCA tracks industry announcements of units that are planning to install NO_x or SO_2 abatement technologies in the near future and models the resulting changes in emission rates, and the variable and fixed costs, associated with the new installations.

To account for SO_2 trading under EPA's Acid Rain Program, the TCA model incorporates the opportunity cost of SO_2 tradable permits into the marginal cost bids, based on unit emission rates and forecast allowance trading prices for the time period of the simulation. GE-MAPS allocates the cost of the SO_2 trading permits to energy throughout the year.

TCA will also model NO_x allowance trading under the Houston–Galveston area Mass Emissions Cap and Trade Program (MECTP) for units in the Houston–Galveston area. TCA is still reviewing the details of this program, and of similar initiatives for the Dallas metropolitan area. TCA models the impact of these programs by adding the value of NO_x allowances to the bid price for holders of such allowances. TCA will adjust the Dallas area based on expected expansion of that attainment area to include additional counties.

TCA’s capacity addition model incorporates the cost of capital equipment required to meet emissions standards.

Data Sources: The EPA’s Clean Air Markets database (2002) provides plant heat input, NO_x and SO_2 emissions, and emission rates. Capital costs for NO_x abatement technology are obtained from EPA’s Regulatory Impact Assessment report for the NO_x Budget Program, originally provided by Bechtel Corporation. Allowance prices are derived from market publications that track allowance trades, principally publications from the Cantor Fitzgerald Environmental Brokerage Service. Projected new SCR installations are obtained from the Argus SCR database, published by Argus Media.

10. External Region Supply

Description: ERCOT is interconnected with the Southwest Power Pool (SPP), the Southeastern Electric Reliability Council (SERC), and Mexico through DC ties at Oklaunion, Monticello, and Maverick County respectively. In addition, a new DC tie with Mexico at Laredo has been approved. TCA can model these DC links either as (1) fixed imports and exports, or (2) as a combination of a load and a dispatchable generator, to simulate the effect of market prices on the flow on the links. The former approach is preferable if the flow on these links is primarily due to long-term contracts. If TCA models the links as a load and generator combination (the latter approach), the load would simulate exports from ERCOT, while the generator would react to locational prices at the DC link by either offsetting the load, or simulating a source of import into ERCOT.

Based on conversations with ERCOT staff, and a review of the historical DC tie flows for Feb–Oct 2003, TCA proposes the following approach:

- The East DC tie will be modeled as equivalent to a gas generator with a heat rate of 8,000 BTU/kWh. If the appropriate zonal or locational price signal is above the 'marginal cost' of this generator, the link will simulate an import of 600 MW.
- The North DC tie at Oklaunion will be modeled as as a firm export from Oklaunion.
- The existing South DC tie in Maverick County will be modeled as zero flow.
- The proposed DC tie at Laredo will be modeled equivalent to a gas generator with a heat rate of 12,000 BTU/kWh, but will run only as an import. That is, the flow on the tie will be zero unless the "price signal" would justify running the equivalent gas generator, in which case 150 MW of import is simulated.

TCA proposes using the capacity of the existing East and North DC ties in capacity reserves accounting. The DC ties to Mexico will not be included in any capacity calculations.

In addition to the DC ties, there are switchable units that can supply power either to ERCOT or to surrounding NERC regions. TCA will include the Kiamichi, Tenaska Frontier, and Tenaska Gateway stations in the ERCOT model and will assume that the units sell into ERCOT.[7] TCA will consider input from Tenaska about alternative representations.

11. Dispatchable Demand (Interruptible Load)

***Description**:* TCA includes a representation of interruptible load. The presence of demand response is important to the energy and installed capacity prices. The value of energy to interruptible load caps the energy prices, and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value. The size of interruptible load is determined as a percentage of total load in ERCOT, based on Interruptible Demand and Direct Control Load Management reported in the EIA-411. This percentage is applied to all load areas. The dispatchable demand for each load area is modeled as a generator with a dispatch price of $600/MWh for the first block (50% of the area's dispatchable demand) and $800/MWh for the second block. These proxy units rarely run in the model, because the high prices they require indicate a supply shortfall and prompt new entry. Thus they play an insignificant role in the energy market, but they play an important role in the capacity market. If these loads can truly be interrupted during peak hours, they will be paid the capacity market-clearing price. Thus they have strong incentives to make themselves available during peak hours. When interruptible demand is included in the calculation of the required reserve margin it reduces the requirement of installed capacity and thus reduces new entry and helps increase energy prices, consistent with market behavior.

***Data Sources**:* The EIA-411 report, as provided by ERCOT, is used as the source for Interruptible Demand and Direct Control Load Management forecast values. Currently they total 1,401 MW, through 2013.

12. Market Model Assumptions

- *Marginal Cost Bidding:* TCA assumes that all generation units bid marginal cost (opportunity cost of fuel plus non-fuel VOM plus opportunity cost of tradable permits). To the extent that markets are not perfectly competitive, the modeling results will reflect the lower bound on prices expected in the actual markets.

---

[7] This is believed to be a reasonable assumption for both cases. If the nodal market results in low prices for these units, it is likely that there is an excess of capacity in their areas such that leaving them in the ERCOT model when they might otherwise switch will have little impact on the overall outcome.

- *Installed Capacity Requirement:* The installed capacity requirement is important in the calculation of capacity prices and in deciding when a given region or market is in equilibrium. Although a centrally administered installed capacity market may not currently exist in ERCOT, the same effect may exist in the form of bilateral markets or may be embedded in energy prices in the form of price spikes. In the first case, in order to meet reliability requirements Load Serving Entities must procure enough capacity to meet their peak demand and reserve requirements. In the second case, generators on the margin of the supply merit order must be profitable in order to stay online and provide reliable supply. A consistently marginal generating unit will therefore communicate to the market its need for capacity payment by raising its bids above marginal generation costs. Regardless of the actual mechanism designed to recover fixed costs, the value of installed capacity should be recognized, quantified, and accounted for in the analysis. The TCA method for estimating this value while the market has a surplus (i.e., while the planning reserve margin is above the anticipated peak plus installed capacity requirement) is based on the computation of the annual revenue deficiency for each generating unit (as a difference of per kW-year fixed operating costs and operating margin received in the market for energy and ancillary services). Using the resulting installed capacity value, TCA models capacity supply curves and computes a capacity price at the point where these curves intersect the capacity requirements. Once the market reserve margin is below the acceptable installed capacity requirement, capacity prices are equal to the carrying charge of a new unit, and such a payment would serve to signal new generation entry. Per conversations with ERCOT staff, TCA proposes 12.5% of net load as an appropriate planning reserve margin.

- *Operating Reserves Requirement (spinning and standby)*: Operating reserves are based on requirements instituted by ERCOT, and may be some combination of spinning and quick-start reserves. The spinning reserves market affects the energy prices, because units that spin cannot produce electricity under normal conditions. Energy prices are higher when reserves markets are modeled. TCA has reviewed the ERCOT Methodologies for Determining Ancillary Service Requirements. Based on the ERCOT requirements, TCA proposes modeling 4,600 MW of operating reserves, of which 1,250 MW are quick-start reserves.

- *Transmission Losses:* Transmission losses will be modeled at average rates based on state mandate.