REPORT ON EXISTING AND POTENTIAL ELECTRIC SYSTEM CONSTRAINTS AND NEEDS WITHIN THE ERCOT REGION

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DISCLAIMER

This report was prepared by the Electric Reliability Council of Texas (ERCOT) System Planning Transmission Services staff. It is intended to be a report of the status of the transmission system in the ERCOT Region and ERCOT's recommendations to address transmission constraints. Transmission system planning is a continuous process. Conclusions reached in this report can change with the addition (or elimination) of plans for new generation, transmission facilities, equipment, or loads.

Information on congestion management presented herein is based on the most recent settlement calculations at the time of the development of this report. True-up settlement statements had been issued through April 2002. Final settlements had been issued through April 2003. Future settlements and Board and Public Utility Commission of Texas directives may change the figures presented herein.

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EXECUTIVE SUMMARY

High-voltage transmission lines serve as an integral link between power generating plants and consumers of electrical energy. Working together, these transmission lines form a transportation highway for electrical power and are often referred to collectively as the transmission grid. The synergism achieved by all components that make up the transmission grid enables the delivery of power to the consumer with minimum disruptions. Major transmission-related components include conductors, support (tower) structures, rights of way, transformers, relays, breakers, switches, reactive devices and remedial action equipment. Some components are essential to the physical act of transmitting power (e.g. conductors); others ensure that the delivered power is of acceptable quality (e.g. reactive devices), while others are required to protect equipment or affect operations and maintenance (e.g. control systems, SCADA, relays and breakers). The transmission system must be flexible enough, every second of every day, to accommodate the growing demand for reliable and affordable electricity.

Retail competition is strong in Texas. In the ERCOT Region where customer choice is in effect[1], over 44% of retail customers have exercised their right to switch to different retail service providers. Over the past 10 years, wholesale competition has been encouraged in electricity markets to lower costs to consumers by spurring needed investments in generation and increasing the efficiency of operations. Today, the transmission system acts as an interstate highway system for wholesale electricity commerce and is the backbone for retail competition.

Daily transmission constraints increase electricity costs to consumers, reduce system reliability, and increase the risk of equipment damage. Two types of constraints are defined in the ERCOT market: (a) commercially significant constraints (CSCs) limit the flow of energy from one of the four major zones in the ERCOT Region into another, and (b) Local Constraints (LCs) limit the flow of energy in areas within a zone in ERCOT.

Reducing transmission constraints is essential to ensuring reliable and affordable electricity now and in the future. Between June 1, 2002, and May 31, 2003, transmission congestion cost ERCOT consumers about $240 million. Costs may have been even greater due to factors not included in this report, such as increased risk of service interruptions that could result from transmission constraints and the use of plants that are less efficient and higher polluting to relieve the congestion. Figure 1 lists the total cost of congestion by cause and by the type of service procured pursuant to the ERCOT Protocols.

Summary of Congestion Costs (in thousands of dollars) June 1, 2002, through May 31, 2003		
Cause	**Type**	**Cost**
CSC Congestion	Balancing Energy Service	$25,624
	Replacement Reserve Service	$0
Local Congestion	Local Balancing Energy Service	$31,942
	OOME	$72,475
	OOMC	$108,206
	Total	**$238,247**

Figure 1 - Summary of Congestion Costs

[1] Refer to ERCOT's Retail Transaction Report at http://www.ercot.com/Participants/PublicMarketInfo/RetailTransaction_reports/Number_Premises_Switched.ppt

Since October 2002, ERCOT has contracted for Reliability Must-Run (RMR) services with several older generating units that are uneconomic in the new market. The net RMR costs from October 2002 through May 2003 have been $78,242,000, which includes Balancing Energy Neutrality Accounts (BENA) credits for the market value of the energy.

The three commercially significant constraints in ERCOT for 2003 are:

- **West Texas to North Texas**
  - Primary corridor is Morgan Creek to Abilene to Graham to Parker
- **South Texas to North Texas**
  - Primary corridor is Marion to Zorn to Austrop to Sandow to Temple to Waco to Venus
- **South Texas to Houston**
  - Primary corridor is Corpus Christi to South Texas Project to Houston

The five most significant Local Constraints in ERCOT are in the following areas:

- **Dallas/Fort Worth**
- **North**
- **Rio Grande Valley**
- **South**
- **West Texas** (McCamey, San Angelo, Morgan East)

Recent announcements on construction of new generation capacity and retirement of older, less efficient units demonstrate the ERCOT market is working effectively. However, competition also changes the landscape:

- New participants enter the market, exit the market, or consolidate their operations, thus changing the players and their contractual supply arrangements.
- Changes in the generation patterns, including the introduction of large, remote wind development, place new challenges on the existing transmission grid.
- Retirement of older plants near metropolitan areas due to economics or environmental restrictions will require a careful assessment of the reliability needs and the transmission alternatives to "must-run" contracts.

ERCOT, along with the transmission service providers, is moving forward on planning necessary transmission to maintain reliable service and to address transmission bottlenecks. The following major ERCOT-recommended projects ***have been completed***:

- **Centerville Switch-McCree Switch 345-kV Line (Completed 2001, 2 miles)**
  - Increase transfer capability across northeast Dallas/Garland area and provide voltage support
- **Fayette-Austrop 345-kV Second Circuit (Completed 2001, 55 miles)**
  - Increase transfer capability from Fayette/Lost Pines to Austin
- **Holman-Lytton 345-kV Second Circuit (Completed 2001, 63 miles)**
  - Increase transfer capability from Fayette/Lost Pines to Austin
- **Limestone-Watermill 345-kV Double-Circuit Line (Completed 2001, 90 miles)**
  - Increase transfer capability between North Texas and Houston
- **Military Highway STATCOM (Completed 2001)**
  - Reduce likelihood of voltage collapse and provide dynamic voltage control
- **White Point 345-kV Switching Station and 138-kV Upgrades (Completed 2001)**
  - Increase transfer capability to/from Corpus Christi area and to provide voltage support
- **Cedar Bayou-King-North Belt-TH Wharton 345-kV Corridor Upgrades (Completed 2002, 49 miles)**
  - Increase transfer capability across east and north Houston and out of Houston
- **Graham-Jacksboro 345-kV Line (Completed 2002, 33 miles)**
  - Critical Status to prevent outage of West Texas and to transport renewable energy out of West Texas
- **Lon Hill-Rio Hondo and Lon Hill-Edinburg 345-kV Lines Series Capacitor Compensation (Complete 2002)**
  - Increase transfer capability to/from Rio Grande Valley and reduce likelihood of voltage collapse

- **Monticello-Farmersville-Valley Junction-Anna Switch 345-kV Line (Completed 2002, 100 miles)**
  - Increase transfer capability into Dallas/Ft. Worth from Northeast Texas, provide for energy delivery across north Dallas, and support voltage in the Dallas/Ft. Worth area
- **San Miguel-Pawnee 345-kV Line and Establish Pawnee 345-kV Station (Completed 2002, 35 miles)**
  - Increase transfer capability to/from South Texas/Corpus Christi/Victoria area and support voltage in the Pawnee/Corpus Christi/Victoria area
- **Venus-Liggett 345-kV Line Upgrade (Completed 2002, 12 miles)**
  - Increase transfer capability into DFW area from the south
- **Anna-Collin 345-kV Line Upgrade (Completed 2003, 16 miles)**
  - Increase transfer capability into DFW area from the north
- **Forney-Centerville Switch 345-kV Line Upgrade (Completed 2003, 15 miles)**
  - Increase transfer capability into DFW area from the east
- **Laredo STATCOM (Completed 2003)**
  - Reduce likelihood of voltage collapse and provide dynamic voltage control
- **Morgan Creek-Red Creek-Comanche Switch 345-kV Line (Completed 2003, 216 miles)**
  - Increase transfer capability from West Texas and deliver renewable energy out of West Texas
- **Pawnee-Coleto Creek 345-kV Line (Completed 2003, 54 miles)**
  - Provide energy deliveries to/from South Texas including Corpus Christi/Victoria area and to support voltage in the Pawnee/Corpus Christi/Victoria area
- **Many 138-kV and 69-kV System Additions/Upgrades including Autotransformers**
  - Provide energy delivery from bulk transmission system to consumers

The transmission service providers are expending hundreds of million of dollars each year upgrading and expanding the transmission system and thereby maintaining reliability, reducing congestion, interconnecting new generation and serving increasing customer demand.

ERCOT has ***supported and recommended*** the following major projects, currently under development by transmission service providers that will help mitigate constraints:

- **Twin Buttes 345-kV Switching Station (Projected 2004)**
  - Critical Status to support voltage in San Angelo and mitigate RMR costs
- **Paris-Anna 345-kV Circuit (Projected 2005, 89 miles)**
  - Needed Status to prevent outage of Northeast Texas during stability events, to provide for energy delivery of Northeast Texas generation into the Dallas/Ft. Worth metroplex, and to support voltage
- **Venus-Liggett 345-kV Line/Circuit (Projected 2005, 28 miles)**
  - Needed Status to provide energy delivery into Dallas/Ft. Worth metroplex
- **Cagnon-Kendall 345-kV Line (Projected 2006, 55 miles)**
  - Needed Status to prevent low voltages and/or loss of load north and northwest of San Antonio and increase ability to transfer power in and out of the San Antonio area
- **Twin Buttes-McCamey 345-kV Line (Projected 2009, 110 miles)**
  - Contingent upon wind developers' final plans for generation additions
- **Odessa-McCamey 345-kV Line (Projected 2009, 50 miles)**
  - Contingent upon wind developers' final plans for generation additions

ERCOT is leading three regional planning groups to determine additional actions needed to serve load and continue to resolve transmission constraints. Major projects currently under study or design development are**:**

- **Anna Switch-Valley 345-kV Line Upgrade (Projected 2004, 27 miles)**
  - Needed Status to provide energy delivery into Dallas/Ft. Worth
- **Watermill-West Levee 345-kV Second Circuit (Projected 2004, 18 miles)**
  - Needed Status to provide energy delivery into Dallas/Ft. Worth
- **Jacksboro-West Denton 345-kV Line (Projected 2005, 50 miles)**
  - Needed Status to provide energy delivery into Dallas/Ft. Worth from the west and to support voltage

- **Watermill-Cedar Hill 345-kV Line (Projected 2005, 17 miles)**
  - Needed Status to provide energy delivery into Dallas/Ft. Worth
- **Jacksboro-Willow Creek-Parker 345-kV Line Upgrade**
  - Needed Status to provide energy delivery into Dallas/Ft. Worth from the west
- **West Levee-Norwood 345-kV Line (Projected 2006, 7 miles)**
  - Needed Status to provide energy delivery into Dallas/Ft. Worth
- **West Denton-NW Carrollton 345-kV Second Circuit (Projected 2007, 20 miles)**
  - Needed Status to transport energy into Dallas/Ft. Worth and to support voltage
- **Clear Springs-Hutto-Salado 345 kV Line (Projected 2008, 90 miles)**
  - Needed Status to provide energy delivery to/from the south and to serve load in the Austin/Pflugerville/Hutto/Georgetown area
- **Edinburg-Frontera 345-kV Line**
  - Needed Status to provide energy delivery to/from the south and to support voltage in Laredo/Rio Grande Valley area
- **Frontera-McAllen 345-kV Line**
  - Needed Status to provide energy delivery into south McAllen area and to reduce local congestion
- **South McAllen-Brownsville-La Palma 345-kV Line**
  - Needed Status to provide energy delivery to east side of Rio Grande Valley and to reduce local congestion
- **San Miguel-Laredo 345-kV Line(125 miles)**
  - Needed Status to provide energy delivery to/from the south and to support voltage in Laredo area
- **Laredo-Frontera 345-kV Line (144 miles)**
  - Needed Status to provide energy delivery to/from the south and to support voltage in Laredo/Rio Grande Valley area
- **Salem-Bryan/College Station-Twin Oaks 345-kV Line and Establish New 345/138-kV Station**
  - Needed Status to provide energy delivery to/from the south and support voltage in Bryan/College Station area
- **Cuero-Holman 345-kV Line and Establish Cuero 345-kV Switch Station**
  - Needed Status to provide energy delivery to/from the south
- **Coleto Creek-Cuero 345-kV Line**
  - Needed Status to provide energy delivery to/from the south
- **Red Creek-Comanche Switch 345-kV Second Circuit**
  - Needed Status to provide energy delivery from West Texas
- **Comanche Switch-Killeen Switch 345-kV Line**
  - Needed Status to provide energy delivery from west and to provide two-way 345-kV service to Killeen
- **Whitney-Concorde 345-kV Line**
  - Needed Status to provide energy delivery from south into Dallas/Ft. Worth
- **Twin Oaks-Lake Creek 345-kV Second Circuit**
  - Needed Status to provide energy delivery to/from south
- **Many 138-kV and 69-kV System Additions/Upgrades Including Autotransformers**
  - Needed Status to provide energy delivery from bulk transmission system to consumers
- **Consideration of 765-kV Transmission**
  - ERCOT is considering the application of 765-kV transmission in Texas. While there is much yet to investigate about the implementation of 765-kV transmission, there are already several interesting findings. Some of the more fundamental characteristics of 765-kV transmission are its low impedance, reducing losses and substantial line charging supporting voltage. Two opportunities have developed to date that have the potential for the application of 765-kV transmission in ERCOT: 1) the delivery of wind power from West Texas to DFW and 2) the balancing of power flows between San Antonio to DFW and Houston to DFW 345-kV transmission corridors. The circumstances are unique but tailored to the application on ERCOT high-voltage transmission.

Electricity use is continuing to grow. This reflects the transformation of the economy to a high-technology information base that relies on electricity. Electricity, though, is not a commodity that can be easily stored, and the transmission infrastructure is at the heart of economic well-being. An open, aggressive, and coordinated transmission planning process that incorporates transmission upgrades to relieve constraints, reliability must-run (RMR) requirements, and the interconnection of new supply (including environmentally friendly units) will be of paramount importance to the future of Texas.

INTRODUCTION

Under the Public Utility Regulatory Act (PURA), ERCOT as the independent organization (IO) is charged with nondiscriminatory coordination of market transactions, system-wide transmission planning, network reliability and ensuring the reliability and adequacy of the regional electric network In addition, the IO ensures access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms.

Transmission planning in the current environment is a complex undertaking that requires significant work by, and coordination among, the IO and the Transmission/Distribution Service Providers (TDSPs), as well as with other market participants. The IO works directly with the TDSPs, with stakeholders/market participants, and through the regional planning groups. Each of these entities has responsibilities to ensure the appropriate planning and construction occurs.

The ERCOT power system consists of those generation, transmission, and distribution facilities that are controlled by individual entities, such as municipal utilities, electric cooperatives, transmission and distribution service providers, and generation resources. Together these entities function as an integrated and coordinated power supply network. On July 31, 2001, the ERCOT Region began operations as a single control area under the direction of ERCOT.

The Texas legislature deregulated the electric wholesale power market in 1995 and mandated the opening of the electric retail power market to competition in most of Texas by 2002. Significant load growth combined with these changes will dramatically affect management of the transmission service in the ERCOT Region.

The interconnected transmission systems are the principal means for achieving a reliable electric supply. They tie together the major electric system facilities, generation resources, and customer demand centers. These systems must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes. These purposes are to:

Deliver Electric Power to Areas of Customer Demand — Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to meet continuously changing customer demands under a wide variety of system operating conditions.

Allow Economic and Competitive Exchange of Electric Power Among Systems — Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic and competitive exchange of electric power among all systems and industry participants. Such transfers help to reduce the cost of electric supply to customers and provide a liquid market.

Provide Flexibility for Changing System Conditions — Transmission capacity must be available on the interconnected transmission systems to provide the flexibility needed to handle a shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.

Electric power transfers have a significant effect on the reliability of the interconnected transmission systems and must be evaluated in the context of the other functions performed by these interconnected systems. In some areas, portions of the transmission systems are being loaded to their reliability limits as the uses of the transmission systems change relative to those for which they were planned and as various obstacles prevent new facilities from being constructed as planned. Efforts by all industry participants to minimize costs will also continue to demand maximum loadings, within safety and reliability limits, on the existing transmission systems.

The competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers as opposed to traditional integrated utility operation, all users of the interconnected transmission systems should understand the electrical limitations of the transmission systems and the capability of these systems to support a wider variety of energy transfers. The challenge

is to plan and operate transmission systems that provide the requested electric power transfers while maintaining overall system reliability.

Traditional planning methods using known generation resources and pairing them with known load are no longer possible. It is uncertain as to which generation will be displaced by newer resources and when and how new generation will affect existing facilities and the transmission system.

Electric systems must also be planned to withstand probable forced and maintenance outages at projected customer demand and anticipated electricity transfer levels. Extreme but less probable contingencies measure the robustness of the electric systems and should be evaluated for risks and consequences. The ability of the interconnected transmission systems to withstand probable and extreme contingencies is evaluated by simulated testing of the systems.

PURPOSE

This report fulfills three requirements. First is the Public Utility Regulatory Act (PURA), as amended by Senate Bill 7 in 1999. PURA section 39.155(b) states:

> "The ERCOT independent system operator shall submit an annual report to the commission identifying existing and potential transmission and distribution constraints and system needs within ERCOT, alternatives for meeting system needs, and recommendations for meeting system needs."

Second is the Public Utility Commission of Texas (PUCT) Substantive Rules Applicable to Electric Service Providers. Section 25.200(c) (4) states:

> "ERCOT shall keep records of the circumstances requiring redispatch and the costs associated with each redispatch and file annual reports with the commission, describing costs, frequency, and causes of redispatch."

Third is the ERCOT Protocols. Section 7.2.2.2(1) states:

> "By October 1 of each year, ERCOT will complete an analysis of load-flow data and expected system additions and will determine expected operating limits and constraints to be used in the designation of CSCs for the upcoming calendar year."

This report was prepared by ERCOT System Planning Transmission Services with the cooperation and assistance of ERCOT Staff, transmission service providers, distribution operation companies, load-serving entities, and generation entities. It contains information that describes currently known ERCOT system constraints, major transmission projects under study to relieve those constraints, and existing transmission projects recommended by ERCOT that address some of those constraints. The new transmission projects discussed in the report are intended to ensure conformance to ERCOT Planning Criteria and North American Electric Reliability Council (NERC) System Reliability Standards. Such projects will be recommended if they provide adequate service to load, interconnect new generation, and provide capacity for energy transactions.

This report documents the process of major changes and additions to the ERCOT transmission grid, helping to ensure continuity in the development of the transmission grid and consistency in the evaluation of grid adequacy. It also helps document the need for new facilities and helps identify the benefits of each project planned, as well as the consequences of project delays.

In addition, this report communicates to generation entities, load-serving entities, other market groups, the public, and the PUCT the nature of transmission constraints and the projects being considered by ERCOT to relieve those constraints. It serves as a starting point for developing proposed projects for approval via the ERCOT Transmission Planning Process, and it may be useful in the preparation of regulatory and other reports that require transmission grid planning information.

REPORT DEVELOPMENT AND PROCESS

Simulation of the transmission grid is necessary to develop this report. Such simulation requires several types of forecasted information that is supplied by various entities. Diversified station load forecasts are derived from the load forecasts for load-serving-entity systems and their undiversified station load forecasts. The load-serving-entity distribution planning requirements, including new substations as well as the load forecasts, are communicated to ERCOT through the Annual Load Data Request (ALDR) process. However, large portions of the future power supply resources are unspecified, that is, there are neither long-term commitments nor accurate long-term predictions for future power supply resources. This, combined with the short lead time to build new generation shortens the transmission planning horizon for new resources to less than three years. Thus, forecasts of generating unit commitment schedules and output levels are often based on best judgment.

A major assumption used in the development of this report is the level of reactive compensation (voltage control) planned on the system. Future assessments and plans will be based upon achieving and maintaining the reactive capability for each load season. With the wheeling of power through the transmission grid, the siting of power supply resources remote from the major load centers, and a reduction in the use of older gas-fired generation during off-peak conditions, reactive compensation has become a very important component of system reliability and ERCOT system security.

The performance criteria used in evaluating system security include NERC Planning Standards and the ERCOT Planning Criteria. Projects included in this report have been and are continuing to be studied for their ability to satisfy the requirements of these standards.

The planning process begins with computer modeling studies of the generation and transmission facilities and substation loads under normal conditions in the ERCOT system. Contingency conditions along with changes in load and generation that might be expected to occur in operation of the transmission grid are also modeled. To maintain adequate service and minimize interruptions during facility outages, model simulations are used to identify adverse results based upon the planning criteria and to examine the effectiveness of various problem-solving alternatives.

The effectiveness of each grid configuration and facility change must be evaluated under a variety of possible operating environments because loads and operating conditions cannot be predicted with certainty. As a result, repeated simulations under different conditions are often required. In addition, options considered for future installation may affect other alternatives so that several different combinations must be evaluated, thereby multiplying the number of simulations required.

Once feasible alternatives have been identified, the process is continued with a comparison of those alternatives. To determine the most favorable, the short-range and long-range benefits of each must be considered including operating flexibility and compatibility with future plans.

COMPUTER SIMULATIONS USED IN THE PLANNING PROCESS

Power system planning is one element of a broader process that leads, ultimately, to the construction of needed facilities. To assess various transmission and non-transmission (generation and load) alternatives, computer models require large amounts of data and projections related to loads, generation, and transmission. Planners use detailed electrical-engineering computer models to assess these alternatives. Model results, combined with information on costs, environmental effects, facility siting, and regulatory requirements, lead to financial and regulatory assessments of different projects. Ideally, these plans lead to the construction of needed projects, cost recovery (including a return on investment) for TDSPs, and transmission rates that charge users for the services they receive.

The purpose of power system planning is to identify a flexible, robust, and implementable system that reliably facilitates competition among suppliers and users, and serves all loads in a cost-effective manner. Meeting this planning goal requires both technical (electrical engineering) analysis of different system configurations and economic analysis of different projects. The computer models used by system planners serve a more modest goal. The modeling

tools show how a particular bulk-power system will behave under a specific set of conditions. They calculate voltages at each bus (node) in the power system and power flows between adjacent buses.

While several types of models are used for planning, they share important characteristics. The most important feature is that the models analyze a particular time period (e.g., the expected summer peak hour in 2004). The system planner must evaluate many scenarios using models to simulate how the system will likely behave under a range of conditions and over various periods of time.

The models do not, by themselves, suggest or determine system enhancements. Instead, they allow the power system planner to simulate the operation of the power system under a range of possible contingencies (e.g., removing a line from service) to see how the system performs. The planner models various infrastructure enhancements to see if they improve system performance to meet both reliability and market needs. The planner uses this information to determine if a proposed enhancement is adequate. The planner must determine which enhancements to model and under what conditions to model the enhancements.

Modeling power systems is difficult, and requires specialized computer tools, because of the scope of the system being modeled rather than the complexity of the individual elements. The problem is that each study, which is essentially a snapshot of a point in time, must cover a broad geographic area, including tens of thousands of pieces of equipment. Alternating current (AC) power systems have few devices that directly control the power flow on individual transmission lines, so it is not possible to segregate a piece of the power system for study. Conditions on one part of the system affect the way the entire system behaves.

Because these analyses must be conducted over the whole ERCOT network, the models require significant amounts of data (some of which is commercially sensitive). Analyzing a condition of practical interest requires numerous model runs. The planner cannot know which individual power lines will be out of service because of maintenance or failure at some future time. Therefore, the system must be modeled repeatedly, removing individual pieces of equipment or transmission line segment from the model one at a time. In addition, the planner must model the system under a range of generation conditions, including different output levels and forced outages.

Different models are used for steady-state, dynamic, and short-circuit analyses, but they all express their results in terms of voltages at each bus and flows through each line and transformer. The models do not select the conditions to be modeled. Neither do they decide what constitutes acceptable performance.

Steady-State Models

Load-flow models, the most widely used tools in transmission planning, calculate the steady-state flows through lines and transformers and the bus voltages throughout the power system under specific conditions. The system planner starts with a model of the system for the time to be studied (e.g., the summer 2004 peak demand). The base case includes system conditions as they are expected to exist at that time, including existing transmission lines and transformers, any new equipment, less any equipment that is retired or no longer in service. Generation and load are set at their expected levels at each bus. The model is run to determine the flows in each line and transformer and the voltages at each bus. These values are examined to assure that no bus voltage is outside its normal operating range and that no line flow is above its limit. The software permits easy manipulation of the input data to test different conditions and contingencies. Loads and/or generation can be adjusted up and down individually or in blocks.

The planner then uses the load-flow model to examine various contingency conditions. The model calculates flows and voltages when, one at a time, each line, transformer, generator, or other element is taken out of service. The planner then uses the model to analyze all credible contingencies; the line flows and bus voltages are examined to ensure that all facilities are within their emergency ratings.

Dynamic Models

While steady-state modeling examines the power system under steady-state conditions, dynamic modeling examines how the system responds to various disturbances that tend to destabilize it. These models analyze system behavior over time intervals ranging from cycles to seconds. They analyze both real-power and voltage stability. All the information required for steady-state modeling is required for stability modeling. Additional information concerning

the dynamic response of the generators and other equipment is also required, including generator inertia, transient and subtransient impedances, governor control characteristics, automatic voltage- regulator characteristics, and protective-relaying response times. Analyzing a power system's dynamic stability is much more complex than modeling steady-state performance.

Transient stability analysis examines the power system's response to severe and sudden changes in system conditions, such as faults, generator tripping, or switching operations. Here, the models identify potential problems with real-power and voltage swings and with generators losing synchronism with the power system. Steady-state stability analysis is similar to transient stability analysis but deals with the system's ability to withstand small disturbances without losing synchronism.

Voltage stability analysis tests the system's vulnerability to voltage collapse. Although different tools are used to examine system dynamic performance, the results are typically converted into line loading limits and generator operating restrictions. By imposing these restrictions on the system before a contingency occurs, the system will remain stable during and after the contingency. Longer transmission lines weaken the coupling between generators and make it easier for generators to pull out of step (lose synchronism).

Fast-acting devices, such as dynamic stabilizers on generators and FACTS (flexible AC transmission system) devices, including static var compensators and superconducting magnetic energy storage, can improve system stability and increase the transmission system's capacity. Dynamic models are used to identify the need for such devices and to quantify how much improvement each device can offer, to determine where to locate the devices, and to specify what control action the devices should take.

Short-Circuit Models

Short-circuit modeling is used to help design the system-protection equipment and to assure that circuit breakers are capable of withstanding and interrupting the largest possible fault current. Short-circuit analysis determines how much fault current might flow at each node in the grid if a short circuit occurs. This information is important because excessive fault current can damage equipment and pose a safety hazard to workers.

Short-circuit studies are done for three reasons: to make sure any change to the system (e.g., adding a generator, reconfiguring lines, or changing a transformer) does not raise fault currents above the interrupting capability of the existing circuit breakers; to inform the designers of new substation equipment the size of breakers that are needed at that location; and to provide information for setting protective relays. These studies are critically important and regularly identify circuit breakers and other equipment that must be upgraded or replaced. However, short-circuit concerns do not generally constrain transmission use because the problems can usually be resolved at modest cost.

Much less data is needed for short-circuit modeling than for load-flow or stability analysis because the geographic scope of short-circuit modeling is very limited. Most loads do not contribute to fault currents, so they need not be modeled. Also, only a few conditions (generally the worst conditions) must be modeled, further simplifying the task. Additional data, however, are required on the equipment being modeled, such as generator transient and subtransient impedances, as well as data for the transmission line and transformer.

Computer Software

Planning simulations are performed using commercially available software suites including PTI Power System Simulator for Engineers (PSS/E), PTI Managing & Utilizing System Transmission (MUST), PowerWorld Simulator, PTL Transient Security Assessment Tool (TSAT), PTL Voltage Security Assessment Tool (VSAT), and PTL Small Signal Analysis Tool (SSAT). In addition, ERCOT has recently expanded its planning tools to include UPLAN Network Power Model (NPM) that simulates both forward-market and real-time dispatch to determine production costs. UPLAN NPM consists of an integrated generation, nodal transmission, and load model that performs a chronological, hourly, security-constrained unit commitment and economic dispatch of all the generation units in the ERCOT market to ensure that transmission security is maintained while serving all of the substation loads.

UPLAN NPM mimics the security constraint function provided operations on a daily basis to assure that generation schedules, which are submitted by QSEs, are adequate to provide a security constrained system (i.e., any N-1

transmission contingency will not overload any remaining elements of the grid). UPLAN NPM adjusts the generation units that are online and their dispatch levels on an hourly basis to ensure that system security is always maintained in the most economical manner. When operations personnel determine that certain generating units needed for reliability are not scheduled for operation by the QSEs that control them, they issue OOMC and/or RMR instructions to ensure that system security can be maintained. Additionally, operations personnel determine any increases or decreases to specific unit schedules that will be necessary to achieve system security for all hours during the next day and then issues OOME up and OOME down instructions to ensure secure operations. UPLAN NPM performs the same security constraint analysis on an hourly basis during the simulation period of interest and through the use of RMR, OOMC, and OOME actions, ensures that the reliability of the system is maintained while serving all of the substation loads in an N-1 transmission secure manner. The only time that UPLAN NPM will not serve all of the substation loads in the system is when no N-1 transmission secure generation unit commitment and dispatch combination exists to reliably serve the load.

These simulations require several types of forecasted information that is supplied by various entities. Diversified substation load forecasts are derived from the load forecasts for the load-serving-entity systems and the undiversified substation load forecasts. The load-serving-entity distribution planning requirements, including new substations as well as the load forecasts, are communicated to ERCOT through the Annual Load Data Request (ALDR) process. However, large portions of the future power supply resources are unspecified, that is, there are neither long-term commitments nor accurate predictions for future power supply resources. This, combined with the short lead time to build new generation, shortens the transmission planning horizon for new resources to less than three years. Thus, forecasts of generating unit commitment schedules and output levels are often based on the planner's best judgment.

CONSERVATION, EFFICIENCY, AND DISTRIBUTED-GENERATION PROGRAMS

Additional conservation, energy-efficiency, and distributed-generation programs may help mitigate transmission constraints and the need for additional transmission. However, in a deregulated retail market, it will be much more difficult to quantify such factors. These factors will be included in future studies only to the extent to which the data can be quantified and locations identified.

REGULATORY AUTHORIZATION

Most new transmission line construction and some line reconstruction require the approval of the PUCT. It is the responsibility of the transmission service provider building the facility to apply for and obtain the Certificate of Convenience and Necessity (CCN) and all other required regulatory approvals. The present PUCT rules allow the PUCT up to 12 months for consideration of the CCN, with some provisions for expedited approval of uncontested applications and critical projects. The need to perform a routing study and for the transmission service provider to hold public meetings typically adds another 12 months to the time required to certify and build a new transmission line. In most new transmission projects, the acquisition of right of way and construction can take up to 12 months after a CCN is granted by the PUCT. As a result, firm commitments should be made at least three years ahead of required in-service dates for most transmission line projects, and some projects may require commitments four to eight years in advance of system needs.

TRANSMISSION CONSTRAINT DEFINITION

A transmission constraint is a physical limitation in the transmission system that prevents the reliable delivery of electricity. It also prevents the full potential of full economic and competitive exchange of electric power among all market participants.

Transmission constraints complicate ERCOT system security management, lead to economic inefficiencies, and can create captive markets. They reduce liquidity of the market and can create "must run" generation, resulting in increased utilization of inefficient units and reduced utilization of more efficient units. Constraints could confer market power to the dominant supplier in a constrained area.

New transmission capacity provided by system improvements maintains reliable service to load, allows new generation to be fully integrated into the grid, provides for additional competition, and promotes lower energy prices. A robust transmission network is required to support a liquid competitive electricity market. Despite their operating importance, the direct cost of transmission facilities is a small fraction of the total cost of electricity, typically much less than 10% of a customer's bill.

Consideration of 765-kV Transmission

Having adequate high-voltage transmission is critical to maintaining reliability under various system conditions. As generation patterns stretch the transmission grid to its limits and beyond, plans for high-voltage transmission system must consider scenarios with heavy power transfers and multiple contingencies. For this reason, ERCOT maintains two transmission planning criteria that exceed the NERC Planning Standards. The first accounts for the possibility that a double-circuit structure could fail removing both circuits from service, and the second recognizes that generators are exposed to catastrophic failures that would make them unavailable for months at a time. The former ensures that ERCOT is prepared to handle the substantial loss of transfer capability caused by the loss of a double-circuit 345-kV line. All three commercially significant constraints between the four balancing energy zones in ERCOT anticipate limitations due to the potential loss of double-circuit 345-kV lines.

The planning criteria recognition of the transmission structure failure supports the use of higher voltage single-circuit transmission circuitry. The voltage levels above 345 kV that are commonly used throughout the United States are 500 kV and 765 kV. Since ERCOT uses 345 kV as its bulk transmission voltage, the step up to 500 kV would have limited benefit due to the small increase in capacity over 345 kV. When added to a network, a new 345-kV circuit improves transfer capability by 0.5 to 1.5 GW as compared to a new 765-kV circuit capable of increasing transfer capability by 1 to 3 GW. The challenge, however, is to introduce sufficient 765-kV transmission facilities to form a network that maximizes the benefit of the higher voltage system.

Introducing 765 kV into the ERCOT transmission grid would take several years to bring to realization, considering the level of study required to justify the investment and the new challenges that would be encountered in the regulatory environment. Given that ERCOT reached 60 GW of load this year, in 10 years at 2.5% growth rate ERCOT will reach 75 GW, and in 20 years would achieve 100 GW. While some of this load growth will be supplied by local generation, if only a quarter of the load growth is ultimately imported into areas lacking generation, over 3 GW more power would need to be transported from remote generation over the next 10 years. Realistically this level of power transfer would require four double-circuit 345-kV transmission lines, but if supplied at 765 kV, a single loop would provide sufficient transmission capacity. Unless a drastic shift to other forms of energy occurs, ERCOT is considering all its alternatives for the transport of electrical energy.

TRANSMISSION PLANNING CRITERIA

In order to maintain reliable operation of the ERCOT power system, all ERCOT market participants must observe and subscribe to certain minimum planning criteria. The criteria described herein combined with the NERC Planning Standards constitute these minimum acceptable requirements. Tests outlined herein are performed to determine conformance to these minimum criteria; however, because ERCOT recognizes that events more severe than those outlined could cause separation, other tests may also be performed, if necessary, for informational purposes.

It is the responsibility of each Transmission and Distribution Service Provider (TDSP) in the ERCOT Region to perform appropriate tests to ensure the reliability of its own transmission facilities. It is also the responsibility of the TDSP to recommend tests and further study to the ERCOT System Planning Function (SPF) or the ERCOT Reliability Operations Subcommittee (ROS) for reliability concerns that may affect multiple TDSPs. Upon consideration of such recommendations, the ERCOT SPF and the ERCOT ROS shall coordinate the performance of tests, as necessary, to assess the reliability of the planned ERCOT power system.

The ERCOT Planning Assessment and Review Working Group (PARWG) will review the ERCOT Planning Criteria every three years to ensure it meets the requirements outlined in the NERC Planning Standards. PARWG will periodically review the planning criteria, procedures, and practices of individual ERCOT TDSPs to ensure consistency with NERC and ERCOT criteria.

The interconnection philosophy of ERCOT is to minimize loss of load by remaining interconnected. Interconnected system planning includes steady-state and dynamic simulated testing by ERCOT TDSPs and the ERCOT SPF to represent specific occurrences for each type of contingency specified below or listed in Table I of the NERC Planning Standards (available at www.nerc.com).

The contingency tests will be performed for reasonable variations of load level, generation schedules, planned transmission line maintenance outages, and anticipated power transfers. At a minimum, this should include projected loads for the upcoming summer and winter seasons within a five-year planning horizon. The ERCOT TDSPs involved should plan to resolve any unacceptable test results through the provision of transmission facilities, the temporary alteration of operating procedures (remedial action plans), temporary special protection systems, or other means as appropriate.

While the requirements listed in NERC Table I address most ERCOT planning concerns, tests will also be conducted to ensure that the planned system conforms to the following additional requirements:

1) The contingency loss of a double-circuit transmission line that exceeds 0.5 mile in length (either without a fault or subsequent to a normally cleared, non-three-phase fault) with all other facilities normal should not cause:
   a) cascading or uncontrolled outages.
   b) instability of generating units at multiple plant locations.
   c) interruption of service to firm demand or generation other than that isolated by the double-circuit loss, following the execution of all automatic operating actions, such as relaying and special protection systems.

No damage or failure of equipment should result from the execution of specific non-automatic predefined operator-directed actions (i.e., remedial action plans). Furthermore, no applicable voltage or thermal ratings should be exceeded as a result of actions, such as generation schedule changes or the curtailment of interruptible load, that may be used in the event of a loss.

With any single generating unit unavailable and with any other generation preemptively redispatched, the contingency loss of a single transmission element (either without a fault or subsequent to a normally cleared, non-three-phase fault) with all other facilities normal should not cause:

   d) cascading or uncontrolled outages.
   e) instability of generating units at multiple plant locations.
   f) interruption of service to firm demand or generation other than that isolated by the transmission element, following the execution of all automatic operating actions, such as relaying and special protection systems.

Furthermore, no damage to, or failure of, equipment should result from the loss, and following the execution of specific non-automatic predefined operator-directed actions (i.e., remedial action plans), such as generation schedule changes or curtailment of interruptible load, no applicable voltage or thermal ratings should be exceeded as a result from the loss.

The ERCOT SPF is responsible for gathering load data for use in the ERCOT load-flow cases via the ALDR. The ERCOT ROS coordinates with the ERCOT SPF in the performance of steady-state and dynamic simulation testing of the bulk power system to determine the impact on the planned system of occurrences of the types of contingencies listed in the NERC Planning Standards. The Steady-State Working Group (SSWG), Dynamics Working Group (DWG), and System Protection Working Group (SPWG) cooperate with the ERCOT SPF to create databases and perform tests as outlined in these criteria.

The databases created by the ERCOT ROS Working Groups and the ERCOT SPF are available for use by ERCOT market participants. It is the responsibility of the individual ERCOT TDSPs to use these databases to perform the appropriate steady-state and dynamic tests to evaluate the compliance of their transmission facilities with the ERCOT Planning Criteria and to recommend, for further study by ERCOT, tests which examine important effects to multiple ERCOT TDSPs or the ERCOT bulk power system. Such tests are discussed by the ERCOT ROS and the ERCOT SPF and are subsequently performed under the direction of either the ERCOT SPF or the ERCOT ROS as appropriate. The individual TDSPs affected by identified issues will pursue appropriate solutions.

TRANSMISSION LINE ROUTING

ERCOT's primary responsibility and concern is the reliability of the supply of electricity in an area that covers about 75% of the state. In carrying out that responsibility, ERCOT performs hundreds of short-range and long-range technical studies to determine where potential problem areas may be and decide what solutions to the technical issues are appropriate. When the studies indicate that new electric transmission facilities are required, ERCOT initiates a review of the technical merits of such facilities before the projects are formally recommended by ERCOT.

In the case of new transmission lines, ERCOT performs no specific routing evaluation or proposal at this stage other than generally trying to favor existing rights of way and avoiding known congested or environmentally sensitive areas. Indeed, it is impossible for ERCOT to do detailed routing evaluations given the number of potential projects to consider and the thousands of potentially affected properties.

Specific routing evaluations and proposals are the responsibility of the particular transmission service provider that develops and constructs each project. ERCOT encourages them to address landowner concerns and reach a mutually acceptable resolution. If that cannot be done, the specific routing issues can be raised and addressed at the PUCT in Certificate of Convenience and Necessity proceedings related to the particular project.

Routes shown in the drawings in this document are for illustration only. Actual routes are the responsibility of the transmission service providers and the PUCT certification process.

ERCOT ENDORSEMENT

Initial inclusion and analysis of proposed transmission projects in this report do not constitute endorsement to begin construction, nor do they indicate a final decision on proposed need or project requirements. The ERCOT Board of Directors will endorse proposed major projects in accordance with the following process:

- ✓ ERCOT staff recommends needed major transmission facility additions based on identified constraints and evaluates proposals from transmission service providers and the requirements for integrating new generating facilities into the ERCOT system.
- ✓ ERCOT conducts an open process of review and comment on proposed major facility additions through committees and subcommittees.
- ✓ ERCOT staff submits final recommended transmission facility additions to the ERCOT Board of Directors for review and concurrence.
- ✓ ERCOT staff determines the designated providers of the additions.
- ✓ ERCOT notifies the PUCT of all Board supported transmission facility additions and their designated providers.

Projects proposed by individual transmission service providers or other stakeholders may also be submitted directly to ERCOT for review.

REGIONAL PLANNING GROUPS

ERCOT leads three regional planning groups (North, South, and West) in the consideration and review of proposed projects to address transmission constraints and other system needs. Participation in these regional planning groups is required of all TDSPs and is open to all market participants/stakeholders, consumers, and PUCT staff personnel. ERCOT staff is responsible for leading and facilitating the RPG processes.

The goals of these regional planning groups are:

- Coordinating transmission planning and construction to ensure that the ERCOT and NERC planning standards are met, that a proposed project addresses ERCOT planning criteria requirements, and that transmission upgrades address needs;
- Improving communication and understanding between neighboring TDSPs on operating procedures, SPSs and RAPs that respond to contingencies, voltage deviations, and facility overloads;

- Preventing inefficient solutions to regional problems through a coordinated effort and resolving the needs of the interconnected transmission systems while ensuring a reliable and adequate network;
- Seeking a cost-effective balance between costs and lead times in the plans produced to ensure and maintain reliable service;
- Planning the bulk transmission system with sufficient lead time to avoid the unnecessary upgrades to the underlying transmission systems taking into account the transfer capacity needs between load and generation pockets to avoid unreasonable congestion costs;
- Along with operations personnel, helping to develop coordinated SPSs and RAPs for new problems that occur, and for problems that appear likely to occur based upon the transmission planning simulations;
- Allowing for stakeholder/market participant and consumer review of all proposed transmission project additions through the submission of adequate project scope documents;
- Allowing for REPs to understand the scope and magnitude of all proposed, planned, and approved transmission projects within ERCOT, so that each can appropriately reflect expected wires cost increases into their retail pricing;
- Integrating renewable technologies under PUCT Substantive Rules and Legislative mandates.

Project endorsement through the ERCOT Regional Planning process is intended to support, to the extent applicable, a finding by the PUCT that a project is necessary for the service, accommodation, convenience, or safety of the public within the meaning of PURA §37.056 and PUCT Substantive Rule § 25.101.

CONGESTION ZONES AND COMMERCIALLY SIGNIFICANT CONSTRAINTS (CSCs)

ERCOT has implemented a zonal balancing energy market design for the resolution of transmission congestion across CSCs based on power-flow calculations. In this market design, the ERCOT transmission grid, including generation resources and load, is divided into a predetermined number of congestion zones. (For a detailed discussion of congestion management in ERCOT, refer to Section 7 of the Protocols.) Figure 2 shows the approximate congestion zones for 2002 and 2003. The zones were not exactly the same for both years, but the differences were not major enough to be distinguishable on the map.

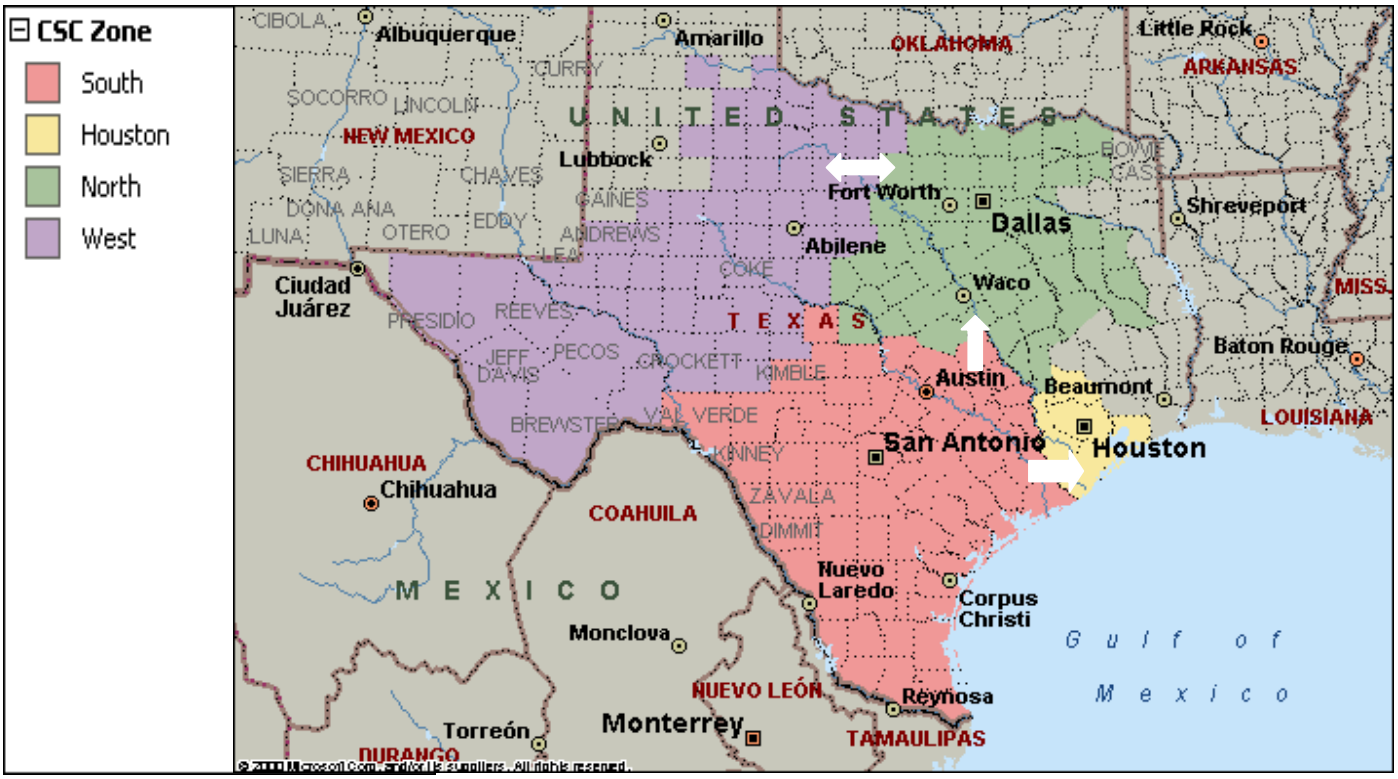

Figure 2 – Congestion Zones for 2002 and 2003

A commercially significant constraint (CSC) is a constraint in the transmission grid that limits the free flow of energy within the ERCOT market to a commercially significant degree. This report does not address the establishment of CSCs as described in the ERCOT Protocols. CSCs are established annually in a stakeholder process for supporting congestion management operations and allocation of zonal congestion management costs. See ERCOT Protocols Section 7 for further explanation of that process. There were four CSCs for 2002: North-West, West-North, South-North, and South-Houston. These CSCs are shown as white arrows in Figure 2. For 2003, the zonal boundaries remained virtually the same as 2002, and there were three CSCs: West-North, South-North, and South-Houston. Zonal congestion is resolved on every 15-minute interval by a linear programming algorithm solving simultaneously for power balance and the CSCs between zones.

Congestion Management Costs For CSCs

The two ERCOT market services utilized for the resolution of CSC congestion are Balancing Energy Service and Zonal Replacement Reserve Service. The costs presented herein include the amounts settled for these two services consistent with the ERCOT Protocols. Final congestion costs reflected in true-up settlement statements and other final re-settlements may vary based on final metering information received at ERCOT.

Balancing Energy Service for Congestion Management

Balancing Energy Service (BES) makes up the difference between total electricity requirements and the sum of the energy schedules on a zonal basis. ERCOT deploys up BES on the load side of the CSC at a marginal incremental price and down BES on the generation side of the CSC at a marginal decremental price based on submitted BES bids. Interzonal congestion management charges are directly assigned to scheduled power flows that impact congested CSCs. Figures 3 and 4 show the balancing energy costs by constraint for 2002 and 2003, respectively.

Balancing Energy Costs for 2002 June 1, 2002, through December 31, 2002	
Constraint	**Cost**
South-North	$2,032,537
West-North	383,648
South-Houston	10,007,433
North-West	678,211
Total	**$13,101,829**

Figure 3 – Balancing Energy Costs for June through December 2002

Balancing Energy Costs for 2003 January 1, 2003, through May 31, 2003	
Constraint	**Cost**
South-North	$3,900,554
West-North	(73,280)
South-Houston	8,694,923
Total	**$12,522,197**

Figure 4 – Balancing Energy Costs for January through May 2003

In 2002, the South-Houston constraint accounted for 76% of the balancing energy costs for congestion management, the South-North constraint accounted for 16% of the costs, the North-West constraint for 5%, and the West-North constraint accounted for the remaining 3%. In 2003, the South-Houston constraint accounted for 69% of the costs and the South-North constraint for 31%. The total balancing energy costs for congestion management between June 1, 2002, and May 31, 2003, were $25,624,026. The cost of each CSC constraint is shown in Figures 5 and 6. The average is calculated by dividing the cost for each constraint by the total number of 15-minute intervals or the number of days. There are 20,544 intervals (214 days x 96 intervals per day) between June 1 and December 31. There are 14,496 intervals (151 days x 96 intervals per day) between January 1 and May 31.

Average Balancing Energy Costs for 2002		
June 1, 2002, through December 31, 2002		
	Per-Interval Costs	**Per-Day Costs**
South-North	$99	$9,498
West-North	$19	$1,793
South-Houston	$487	$46,764
North-West	$33	$3,169
Total	**$638**	**$61,224**

Figure 5 – Average Balancing Energy Costs for June through December 2002 (Based on 20,544 intervals)

Average Balancing Energy Costs for 2003 January 1, 2003, through May 31, 2003		
Constraint	**Per-Interval Costs**	**Per-Day Costs**
South-North	$269	$25,831
West-North	($5)	($485)
South-Houston	$600	$57,582
Total	**$864**	**$82,928**

Figure 6 – Average Balancing Energy Costs for January through May 2003 (Based on 14,496 intervals)

Zonal Replacement Reserve Service

Replacement Reserve Service (RPRS) is procured from generation units planned to be off line and loads acting as resources that are available for interruption during the requirement period. When deployed, units providing RPRS are capable of providing additional balancing energy service to ERCOT. Replacement Reserve Service was not required between June 1, 2002, and May 31, 2003.

Local Constraints (LCs)

Local constraints are bottlenecks that limit the flow of energy in areas within one congestion zone. ERCOT has identified eleven general areas with local constraints. These areas are Austin, Corpus Christi, Dallas/Fort Worth (DFW), Houston, Laredo, North, Rio Grande Valley, San Antonio, South, West, and Wind. The most significant of these areas are Dallas/Fort Worth, North, Rio Grande Valley, South, and West (McCamey, San Angelo, Morgan East). These five areas account for 82% of the total local balancing and out-of-merit costs.

Congestion Management Costs For LCs

Three ERCOT market services are utilized for the resolution of local congestion: Local Balancing Energy Service, Out-of-Merit Energy, and Out-of-Merit Capacity. While these services may be procured for other reliability needs, the costs included in this report are those incurred in the resolution of local congestion in the ERCOT LCs.

Local Balancing Energy (LBE) Service

Local Balancing Energy Service is used to manage local congestion when the market solution test is met in accordance to Section 7 of the ERCOT Protocols. Figure 7 shows the local balancing costs by local area for June 1, 2002, through May 31, 2003. The North area accounts for most of the costs, with 38%.

Local Balancing Energy Costs			
June 1, 2002, through May 31, 2003			
Area	**Up**	**Down**	**Total**
Austin	$846,128	$202,234	$1,048,362
Corpus Christi	$3,864,408	$562,356	$4,426,764
DFW	$1,265,150	$202,002	$1,467,152
Houston	$50,777	$100,159	$150,935
Laredo	$355,972	$966	$356,938
North	$2,038,261	$10,112,388	$12,150,648
San Antonio	$402,102	$455,352	$857,453
South	$1,254,161	$2,348,103	$3,602,264
Valley	$3,299,824	$96,882	$3,396,706
West	$2,620,681	$1,679,602	$4,300,283
Wind	$86,237	$98,294	$184,531
Total	**$16,083,701**	**$15,858,336**	**$31,942,037**

(Totals may not match because of rounding.)

Figure 7 – Local Balancing Energy Costs

Out-of-Merit Energy (OOME) Service

OOME services are provided by resources selected by ERCOT outside the bidding process in order to resolve local congestion when no market solution exists. Resources include generators or loads acting as resources listed as "on line and available" in the resource plan. OOME is captured in system-generated and logged instructions as well as verbal dispatch instructions. Figure 8 shows the OOME costs by local area for June 1, 2002, through May 31, 2003. The North area accounts for most of the costs, with 30%.

OOME Costs			
June 1, 2002, through May 31, 2003			
Area	**Up**	**Down**	**Total**
Austin	$1,924,412	$40,527	$1,964,939
Corpus Christi	$2,653,558	$1,053,500	$3,707,058
DFW	$8,485,267	$347,845	$8,833,112
Houston	$5,160,434	$879,688	$6,040,122
Laredo	$1,916,147	$1,500	$1,917,647
North	$1,626,128	$19,891,184	$21,517,312
San Antonio	$984,872	$122,388	$1,107,260
South	$2,295,849	$8,017,812	$10,313,662
Valley	$4,651,852	$3,111,168	$7,763,020
West	$1,551,180	$1,247,427	$2,798,607
Wind	$962,872	$5,549,372	$6,512,244
Total	**$32,212,571**	**$40,262,412**	**$72,474,983**

Figure 8 – Total OOME Costs (Totals may not match because of rounding.)

Out-of-Merit Capacity (OOMC) Service

OOMC is used to provide for generation capacity needed such that balancing energy is available to solve local congestion or other reliability needs when a market solution does not exist. OOMC can be provided from any resource or load acting as a resource that is listed as available in the resource plan. Figure 9 shows the total OOMC costs for June 1, 2002, through May 31, 2003. The DFW area accounted for 66% of the total OOMC costs and the Valley area for 17%.

OOMC Costs	
June 1, 2002, through May 31, 2003	
Area	**Total**
Austin	$237,411
Corpus Christi	2,582,594
DFW	71,820,468
Houston	1,851,513
Laredo	3,634,803
North	1,308,342
San Antonio	1,956,353
South	5,978
Valley	18,390,557
West	6,418,380
Wind	0
Total	**$108,206,398**

Figure 9 - Total OOMC Costs by Local Area

Figure 10 shows the total OOM costs. OOMC accounted for 60% of the total OOM costs and OOME for 40%.

Total OOM Costs	
June 1, 2002, through May 31, 2003	
OOME	$72,474,983
OOMC	108,206,398
Total	**$180,681,381**

Figure 10 – Total OOM Costs

FREQUENCY OF CONGESTION

For the purposes of this document "frequency" will be defined as either

a) the number of 15-minute intervals that balancing energy service was used to manage congestion, or
b) the number of times generating units were instructed to increase or decrease their level of generation (OOM'd) in order to manage congestion. For LBE and OOME the frequency is based on 15-minute intervals, for OOMC on hourly intervals.

Balancing Energy Service for Congestion Management

The number of 15-minute intervals where balancing energy was needed to manage congestion is shown in Figures 11 and 12 for 2002 and 2003, respectively.

Intervals of Balancing Energy for Congestion Management June 1, 2002, through December 31, 2002	
Constraint	**Intervals**
South-North	1,045
West-North	75
South-Houston	2179
North-West	686
Total	**3,985**

Figure 11 – Intervals of Balancing Energy for Congestion Management for 2002 (Based on 20,544 intervals)

Intervals of Balancing Energy for Congestion Management January 1, 2003, through May 31, 2003	
Constraint	**Intervals**
South-North	302
South-Houston	5
West-North	784
Total	**1,091**

Figure 12 – Intervals of Balancing Energy for Congestion Management for 2003 (Based on 14,496 intervals)

Of the 20,544 intervals between June 1 and December 31, balancing energy was needed in 11% of the intervals for the South-Houston constraint and in 5% of the intervals for the South-North constraint. In 2002, the South-Houston constraint accounted for 55% of the times that balancing energy was used for congestion management.

Of the 14,496 intervals between January 1 and May 31, balancing energy was needed in 5% of the intervals for the West-North constraint and 2% of the intervals for the South-North constraint. In 2003 for the intervals in which balancing energy was needed, the West-North constraint accounted for 72% and the South-North constraint for 28%.

Local Balancing Energy Service

Figure 13 shows the number of times by area that generating units were instructed to change the operating level for local balancing energy service. It is possible to have more OOME instructions than the number of intervals in the period. For example, if two units were needed to clear one constraint, then that is considered as two times even when it is the same interval.

Total LBE Instructions	
June 1, 2002, through May 31, 2003	
Area	**Instructions**
Austin	2,969
Corpus Christi	2,003
DFW	2,699
Houston	355
Laredo	557
North	11,274
San Antonio	4,720
South	12,770
Valley	2,365
West	4,873
Wind	685
Total	**45,270**

Figure 13 – Total LBE Instructions (Based on 15-minute intervals)

For this period the South area accounted for 28% of the local balancing energy instructions and the North area for 25%. The Houston area had the least number of LBE instructions.

Out-of-Merit Service

Figure 14 shows the number of times by area that generating units were instructed to change the operating level for out-of-merit service for energy (OOME). Figure 15 shows the same information for out-of-merit service for capacity (OOMC).

Total OOME Instructions	
June 1, 2002, through May 31, 2003	
Area	**Instructions**
Austin	4,011
Corpus Christi	13,865
DFW	22,020
Houston	12,417
Laredo	10,922
North	26,718
San Antonio	7,864
South	35,110
Valley	46,743
West	13,085
Wind	312,771
Total	**505,526**

Figure 14 – Total OOME Instructions (Based on 15-minute intervals)

For the time between June 1, 2002, and May 31, 2003, the Wind area accounted for 62% of the OOME instructions. The Austin area had the least number of OOME instructions during the period.

Total OOMC Instructions	
June 1, 2002, through May 31, 2003	
Area	**Instructions**
Austin	24
Corpus Christi	1,860
DFW	25,519
Houston	1,321
Laredo	3,329
North	1,105
San Antonio	419
South	110
Valley	9,579
West	4,604
Wind	0
Total	**47,870**

Figure 15 – Total OOMC Instructions (Based on hourly intervals)

For the time between June 1, 2002, and May 31, 2003, the DFW area accounted for 53% of the OOMC instructions and the Valley area for 20%.

CAUSES OF CONGESTION

Figure 16 lists the names, limiting elements, contingencies, and other information about the repeated local constraints between June 1, 2002, and May 31, 2003.

Repeated Local Constraints June 2002 through May 2003

Area	OC_Name	Limiting Elements	Contingencies	Limit	When Congestion Occurred
Valley	Valley import	Rio Hondo-Nedinburg 345-kV line	Rio Hondo-Lon Hill 345-kV line	Line ratings	06/02, 12/02-01/03, 04/03-05/03
DFW	West Levee Auto	West Levee Auto	West Levee Auto	Auto rating	06/02, 08/02-09/02, 01/03, 04/03-05/03
San Antonio	Marion_HillCtry_Skyline	Schertz-Parkway 138kV Marion-Cibolo 138kV	DBL CKT 345kV Marion-Hill Country & Marion-Skyline	Line ratings	06/02, 09/02-12/02, 05/03
Laredo	ASHERTON_EAGLEPASS_071301	138kV Asherton-Eagle Pass	Base Conditions	Line ratings	06/02, 08/02-10/02
Austin	Austrop_Auto_Outage				12/02, 03/02
Valley	BATES_AUTO_BASE	Bates Autotransformer	Base Conditions	Auto rating	06/02-05/03
Laredo	BATES_GARZA_BASE	Bates-Garza 138kV	Base Conditions	Lineratings	06/02-08/02, 10/02, 02/03
DFW	DALLAS_MINIMUM_GENERATION	Autos: Ligget, NW Carrolton,Sherry, W. Levee,Everman, Norwood, Centerville. Lines: 138kV Liggett-DFW, Ligget-Euless,Carrolton NW - Carrolton	Base Conditions and various 345kV lines connected to the area	Auto/line ratings	08/02, 10/02
Corpus Christi	DAVIS_UNLOADED				08/02-09/02
Valley	EDINBURG-MCC0L	138kV Edinburg-McColl	Base Conditions	Line ratings	06/02-10/02, 12/02, 03/03
DFW	EVERMAN_AUTO_BASE	Everman Auto	Everman-Sherry/Cedar Hill 345-kV line	Auto rating	06/02-07/02, 10/02
Wind	Ftln_Illn_69kV	69kV Ft. Lancaster - Illinois	Base Conditions	Line ratings	06/02, 09/02-11/02, 05/03
North	GRAHAM_TO_WEST	138/69 kV lines	Graham-Morgan/Sweetwater	Line ratings	06/02, 08/02, 10/02-05/03
Valley	La Palma #6-Increase	Rio Hondo-La Palma 138-kV line	Rio Hondo-La Palma 138-kV line	Line ratings	06/02-11/02, 05/03
DFW	LiggetNorth-DFW	Ligett-Euless 138-kV line	Norwood-Cedar Hill/Liggett 345-kV line	Line ratings	06/02-08/02
West	MORGAN_TO_EAST	Eskota-S. Abilene 138-kV line	Graham-Parker Double-circuit 345-kv line	Line ratings	06/02, 08/02-10/02, 02/03-05/03
Valley	NEDIN TO RIO HONDO	138kV Rio Hondo-La Palma	345kV Rio Hondo-Edinburg or 345kV Rio Hondo-La Palma	Line ratings	06/02, 08/02-12/02, 02/03, 04/03-05/03
North	NORTH TO HOUSTON	Gibbons Creek-Obrien 345-kV line	Jewett-Tomball-Gibbons Creek-King 345-kV line	Line ratings/voltage	10/02-12/02, 05/03
Corpus Christi	NUECESBAY_WHITEPOINT	Nueces Bay-Whitepoint	Base Conditions	Line ratings	06/02-01/03
DFW	NW Carrollton Auto	Auto	Allen SW-Royce/Monticello 345-kV line	Auto rating	08/02-10/02, 02/03, 05/03
Wind	RIOP_138BUSTIE_RIOP6	Crane AEP - Crane Oncor	Base Conditions	Line ratings	06/02-08/02

Area	OC_Name	Limiting Elements	Contingencies	Limit	When Congestion Occurred
Valley	SE_EDINBURG_PHARR_JMA	S. Edinburg-Pharr	NE Edinburg-Rio Hondo 345-kV line	Line ratings	06/02-08/02
DFW	SHERRY_AUTO-071901	Sherry Auto	Base conditions	Auto rating	06/02-09/02
North	TRADINGHOUSE_VENUS_BASE	138/69-kV line north to south	Lake Creek-Temple,Tradinghouse-Temple 345-kV	Line ratings	06/02, 10/02, 02/03
North	TRINIDAD_MALAKOFF2			Line ratings	09/02-10/02, 12/02, 02/03-03/03
South	VICTORIA_THOMSTN17				06/02-10/02, 05/03
Wind	West_Texas_Wind_Farms_Gen_Reduction	138/69-kV lines	Big Lake-McCamey 138-kV line	Line ratings	06/02, 08/02-12/02

Figure 16 – Repeated Local Constraints

CONGESTION COST SUMMARY

In accordance with Section 7 of the Protocols, ERCOT has established congestion zones and commercially significant constraints. There were four zones in 2002 and four in 2003. CSC congestion is congestion between the zones; local congestion is congestion within one zone. Figure 17 presents a summary of the congestion costs by cause and by the type of service procured under the ERCOT Protocols.

Summary of Congestion Costs June 1, 2002, through May 31, 2003		
Cause	**Type**	**Cost**
CSC Congestion	Balancing Energy Service	$25,624,026
	Replacement Reserve Service	0
Local Congestion	Local Balancing Energy Service	31,942,037
	OOME	72,474,983
	OOMC	108,206,398
	Total	**$238,247,444**

Figure 17 – Summary of Congestion Costs

Out-of-merit for capacity service accounts for the largest category of the congestion costs, approximately 45%. Out-of-merit service for energy accounts for about 30% and local balancing energy about 13%. Balancing energy service for constraint management accounts for about 11%. The average cost of congestion per 15-minute interval is about $6,800 and per day is about $652,700.

The frequency of congestion in this document is defined as the number of intervals that balancing energy service was used for congestion management or the number of times generating units were instructed to increase or decrease output for out-of-merit service. Between June 1 and December 31 of 2001 balancing energy service was used in 3,985 15-minute intervals for congestion management. Between January 1 and May 31 of 2003 it was used in 1,091 intervals. This is a total of 5,076 intervals, or 15% of the time, that balancing energy service was needed for congestion management.

The total number of times units were instructed to adjust their level of output to manage congestion for LBE between June 1, 2002, and May 31, 2003, was 45,270. The total number of times units were instructed for OOME was 505,526 and for OOMC was 47,870 times.

RELIABILITY MUST-RUN SERVICE

Units defined as Reliability Must-Run (RMR) units are those operated under the terms of an annual agreement with ERCOT. These units would not otherwise be operative except that they are necessary to provide voltage support, stability, or management of localized transmission constraints under first contingency criteria where market solutions do not exist. RMR service is the provision of generation capacity or energy resources from a RMR unit or a synchronous condenser unit.

RMR service was first paid in October 2002. Figure 18 shows the net costs for RMR service. The net costs are RMR payments including Balancing Energy Neutrality Account (BENA) credits for the market value of the energy. RMR costs include standby, startup, energy to provider, and energy imbalance. BENA credits reflect the positive effect of the RMR generation (effectively reducing other generation and creating a payment back to the market).

Month	RMR Payments	BENA Credit	RMR Net Costs
Oct-02	$17,100,000	($6,490,000)	$10,610,000
Nov-02	14,734,000	(3,966,000)	10,768,000
Dec-02	15,910,000	(5,283,000)	10,627,000
Jan-03	18,438,000	(7,925,000)	10,513,000
Feb-03	28,583,000	(24,612,000)	3,971,000
Mar-03	17,493,000	(7,632,000)	9,861,000
Apr-03	15,426,000	(5,849,000)	9,577,000
May-03	32,617,000	(20,302,000)	12,315,000
Total	**$160,301,000**	**($82,059,000)**	**$78,242,000**

Figure 18 – RMR Net Costs

The units that had RMR contracts with ERCOT during this time are Barney M. Davis units 1 and 2, J.L. Bates units 1 and 2, Frontera unit 1, Fort Phantom unit 2, La Palma units 4, 5, 6, and 7, Laredo units 1, 2, and 3, Rio Pecos unit 6, and San Angelo units 1 and 2.

ERCOT PLANNING REGIONS

ERCOT leads three regional planning groups (North, South, and West) in the consideration and review of proposed projects to address transmission constraints and other system needs. Participation in these regional planning groups is required of all TDSPs and is open to all market participants/stakeholders, consumers, and PUCT staff personnel. ERCOT staff is responsible for leading and facilitating the RPG processes. Figure 19 illustrates the geographic area covered by each regional planning group.

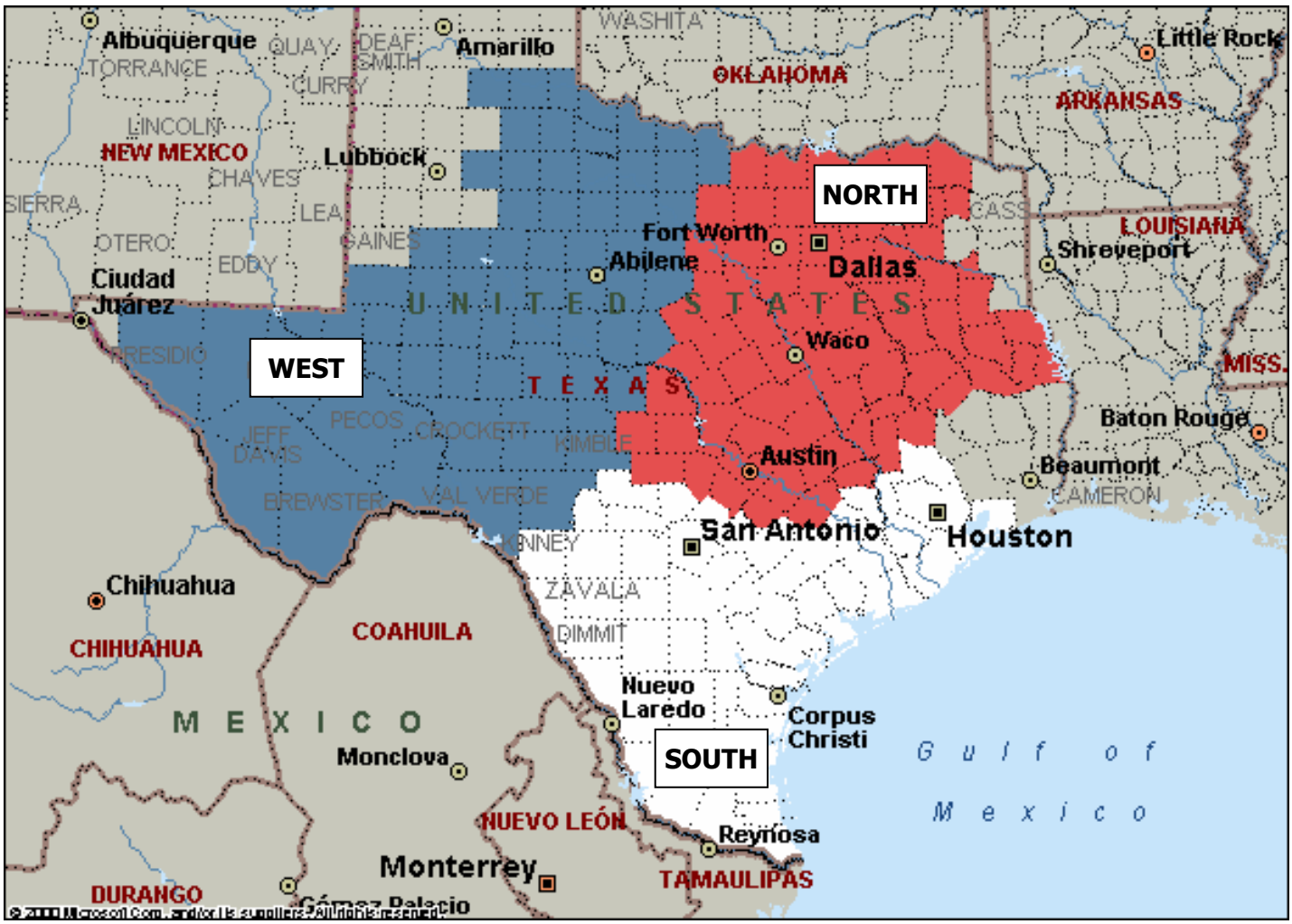

Figure 19 – ERCOT Planning Regions

SOUTH REGION DISCUSSION

The ERCOT South Region consists of 55 counties and 34,638 MW of generation. It had 23,906 MW of coincident peak load in 2002. These numbers represent approximately 44% of the total ERCOT generation capacity and 44% of total ERCOT coincident peak load. Geographically, the region encompasses the San Antonio and Houston metropolitan areas as well as the Rio Grande Valley and smaller centers of load in Laredo, Del Rio, Corpus Christi, and Victoria. Non-coincident load growth for 1998 to 2002 in the 55-county South Region was approximately 2.9% per year compared to the average load growth of 3.5% for all of ERCOT. The largest increases in load occurred in counties near the San Antonio and Houston metropolitan areas. Based upon percentage, counties located in the Rio Grande Valley and Corpus Christi areas also ranked near the top in growth.

There were few new generators put in service in the South Region during 2003. About 600 MW of new generation became commercially available in the Houston area.

The following summaries highlight some of the transmission-related concerns within the South Region.

Local Constraints

Local constraints in the South Region continue to represent a large amount of the Local Balancing Energy (LBE), Out-of-Merit Capacity (OOMC) and Out-of-Merit Energy (OOME) costs for ERCOT. Transmission planning and construction has not been able to keep pace with load growth and changes in generation patterns that have resulted from a deregulated environment. Local congestion continues to be a troublesome problem throughout the South Region. For the period of June 1, 2002, through May 31, 2003, 35% of LBE, OOME, and OOMC payments were for local congestion in the South Region. Overall, ERCOT has RMR contracts with 10 units in the South Region. RMR contracts are required for several units in the Rio Grande Valley, as well as in Corpus Christi and Laredo. Between October 2002 and May 31, 2003, $62 million of RMR payments have been made to units in the South Region. ERCOT anticipates congestion costs continuing until significant transmission improvements are made.

Commercially Significant Constraints

The South Region incorporates almost all of the 2004 Houston and South commercially significant constraint (CSC) zones. For 2004, three of the four CSCs will be for controlling flows associated with the South Region.

Currently, the Sandow-Temple circuit is the CSC used to control the flow from the South CM zone into the North CM zone. Historically, the South Region has been a net exporter of power to the rest of ERCOT. For many years the Big Brown-Jewett 345-kV double circuit was the limiting contingency for South to North flows. After the addition of the Limestone-Watermill 345-kV circuit in 2001, the limiting contingency became the Sandow-Temple 345-kV double circuit for that same South to North power transfer. Underlying 138-kV elements that are susceptible to overloads for this contingency include the Bellville South–Peters line and the Minerva–Milano line.

Recently, new generation has come online in the North CM zone while some older Houston area generation has been mothballed. As a result, ERCOT has begun to see flows from the North into the Houston CM zone that cause contingency overloads. This congestion initially appeared in 2002 as a seemingly isolated and rare event but reappeared in 2003 as a major constraint in terms of economic impact. ERCOT basecases, developed by the Steady-State Working Group, show this flow reoccurring in future years. This has resulted in a new CSC to control this flow. The most limiting thermal constraint was the loading of the Gibbons Creek–Obrien circuit. However, soon after the constraint was identified, the Gibbons Creek – Obrien circuit was upgraded, effectively increasing the emergency rating of the circuit by about 300 MVA. As a result, North to Houston transfer capability has been increased, but is still constrained. The Jewett –T. H. Wharton and Jewett–Tomball 345-kV circuits are now the limiting thermal elements, with the thermal limit based upon equipment ratings at Jewett substation. However, at peak load times, North to Houston transfers are also limited by voltage stability and angular stability considerations.

The third CSC affecting the South Region controls flow into the Houston CM zone from the South CM zone. For South to Houston congestion, the South Texas Project (STP) to W. A. Parish (WAP) circuit has historically been the limiting element. This circuit was upgraded in 2003, largely removing thermal limitations. The Bellville South–Peters

138-kV line is now the most commonly observed limiting element for the loss of the STP-Dow 345-kV double-circuit contingency. This line, which is a tie between LCRA and CenterPoint Energy, is scheduled to be upgraded by summer 2004. South to Houston transfers are also limited by voltage stability considerations, and even if those constraints were addressed, high transfer levels could cause angular stability concerns.

Corpus Christi

The Corpus Christi area, located on the Gulf Coast approximately halfway between Brownsville and Houston, is primarily served by American Electric Power (AEP). The region has about 1,700 MW of peak load and 1,800 MW of generation. Local congestion in the area has resulted in a RMR contract with the Barney Davis units.

A new 345-kV station serving the Corpus Christi area is planned between Lon Hill and Rio Hondo for 2006. The new station will be located approximately 10 miles south of the existing 345-kV Lon Hill substation and will alleviate 138-kV constraints caused by the import of power from the north as well as eliminate the need for a RMR contract with the Barney Davis units. In addition, the new station will help improve voltage recovery in the area following a transient event.

Houston

Houston is one of ERCOT's two largest load centers. Primarily located in Harris County, the Houston metropolitan area has more than 4 million residents. The region also contains about 23,000 MW of generation and 18,000 MW of load. CenterPoint Energy provides transmission service to the majority of the area load. Texas New Mexico Power (TNMP) also serves a portion of the load.

Houston has been a prime area for Independent Power Producer (IPP) development in recent years. The Deer Park Energy Center (DPEC) generating plant was interconnected in 2002 with generating units being brought online in stages throughout 2004. The South Houston Green Power (SHGP) generating plant is being interconnected in 2003 and will be in commercial operation early in 2004. When the DPEC and SHGP plants are completed early next year, approximately 6,000 MW of new generation will have been added to the area since 1999. Like other areas of ERCOT, many of the older generating units in the area have been mothballed or are seldom used.

Direct interconnections of new generating plants and upgrades relating to changes in generation dispatch patterns have been completed in a timely manner during this period, resulting in minimal internal congestion costs and no RMR units in the Houston CM zone. Because the DPEC and SHGP plants both connect through transmission lines to the existing P. H. Robinson substation (PHR), additional transmission upgrades are being built or planned in that station's general vicinity. PHR, Obrien, Jeanetta, and T. H. Wharton substations each have 345/138-kV autotransformers that are being added or upgraded. Various other transmission system improvements are being constructed or planned due to changes in generation dispatch patterns and load growth. Autotransformers and circuits at several other locations, including Greens Bayou, Cedar Bayou, Bellaire, and the downtown area, have been highly loaded on several occasions and have occasionally caused OOM generation dispatch. These problems are being studied, and additional upgrades may be necessary.

A few years ago, ERCOT approved a plan to build "Oasis" substation. Oasis was originally conceived to help address thermal loading concerns along the north Houston 345-kV corridor (Cedar Bayou–King–North Belt–T. H. Wharton). However, as more generation was added to the east side of Houston, subsequent analyses indicated that the entire north Houston corridor would need to be upgraded using high-temperature conductor regardless of whether Oasis substation was built, so Oasis was deferred indefinitely. Recent analysis has revealed that Oasis substation, combined with an upgrade of the Oasis to WAP 345-kV circuit, would help address loading concerns in the PHR area following the completion of the DPEC and SHGP generating plants. These projects would also improve voltage and angular stability limitations for South to Houston transfers, thereby reducing South to Houston congestion. Oasis substation would also prevent voltage collapse under the contingency loss of the north Houston corridor following the completion of the DPEC and SHGP generating plants. For all these reasons, the deferred Oasis substation project is now being reconsidered.

A possible alternative to the Oasis substation project is building a PHR to WAP 345-kV circuit. This would add a circuit to existing transmission structures that are now used for the PHR–Dow–WAP circuits. This alternative, however, would require a CCN from the Public Utility Commission and would therefore take longer to implement, without offering any cost or performance gains to justify the delayed implementation.

Rio Grande Valley

The Rio Grande Valley area is located in the far south Texas counties of Cameron and Hidalgo. Major population centers include McAllen, Harlingen, and Brownsville. AEP and Magic Valley Electric Co-op provide transmission service to the majority of the "Valley." The City of Brownsville and Sharyland Utilities also serve portions of the region. There are approximately 1,800 MW of load and 2,400 MW of generation in the area.

The Valley continues to be a source for large amounts of congestion and RMR costs. Even with improvements made in 2003, in both the east and west sides of the Valley the underlying 138-kV system is not adequate to transport power from the 345-kV system to area loads under contingency conditions. ERCOT currently has RMR contracts with units on both sides of the Valley in order to maintain reliability. In addition, dynamic stability problems exist for large power transfers into Laredo from the Rio Grande Valley. Load in the Valley continues to grow at a rate that exceeds the average for the rest of ERCOT.

There are numerous 138-kV and 69-kV improvements scheduled in the next few years that will relieve the current RMR generation contracts for the La Palma and Bates units; however, the long-term solution will be the extension of the 345-kV system farther south along the border area. On the west side of the Valley a 345-kV line from North Edinburg to South McAllen is scheduled for 2007 eliminating the long-term need for the RMR generation in the Mission area. On the east side of the Valley a 345-kV line from Rio Hondo to a new 345-kV station in the Brownsville area will eliminate the long-term need for RMR generation in that area. This 345-kV extension will eventually be connected with a line that would parallel the US and Mexico border completing a South Valley 345-kV loop at South McAllen. New generation, potential CFE asynchronous interconnections, and the expansion of the 345-kV system to Laredo may also play a role in meeting the long-term load growth in the Rio Grande Valley and improving the overall import and export capabilities of the area.

Laredo

The Laredo area, located in Webb County, is primarily served by 138-kV and 69-kV transmission owned by AEP. It is located on the Texas and Mexico border approximately 150 miles northwest of the Valley. The area contains approximately 370 MW of peak load and 170 MW of generation. Generation at the Laredo Plant is critical for maintaining system reliability in this area.

The Laredo area continues to have large amounts of congestion and RMR costs. ERCOT currently has a RMR contract with the Laredo units in order to protect against voltage collapse and thermal overloads. Analysis shows the possible voltage collapse for a single contingency outage when no generation is online in Laredo. The addition of capacitors is planned for the summer of 2004 to correct this problem. In addition, conductor upgrades to the 138-kV and 69-kV systems are also planned; however, these improvements will not eliminate the need for the Laredo RMR contract. Laredo continues to grow at a 5% rate.

Possible solutions currently under study include the installation of an asynchronous interconnection with Mexico or conversion of the Alice to Freer to Laredo 69-kV line to 138 kV. The extension of the 345-kV system out of the San Miguel plant would provide a long-term solution that not only benefits Laredo, but also the Valley by relieving power flows that currently flow north out of the Valley. The 345-kV extension would require the construction of approximately 110 miles of line. Tying the Laredo 345-kV extension into the Valley would require another 150 miles of 345-kV construction. This 345-kV line would provide a second 345-kV source to Laredo and a third 345-kV source to the Valley. The economics of all of these alternatives are highly dependent on the cost of congestion.

San Antonio

The San Antonio metropolitan area is primarily served by City Public Service (CPS). CPS is a municipally owned electric and gas utility that also serves small load portions in the adjacent Atascosa, Bandera, Comal, Guadalupe, Kendall, Medina, and Wilson counties. CPS serves approximately 604,000 electric customers within its 1,566-square-mile area. The peak system load reached 4,117 MW in August 2003.

Electric load served by CPS is provided mostly by local CPS-owned generation plants and nuclear power imported from the STP. CPS total generation capacity is 5,216 MW, of which 1,425 MW is from coal, 2,931 MW from natural gas, 700 MW from nuclear power, and 160 MW from wind power. The CPS transmission system consists of approximately 807 miles of 138-kV lines and 570 miles of 345-kV lines. San Antonio has elected not to opt-in to retail market competition. However, CPS does import and export bulk power to the ERCOT system.

The CPS distribution system is experiencing highest load growth in the northern part of the city, more specifically along corridors of Loop 1604 and Highway 281, IH 10, and Highway 16. The area is experiencing load growth from 9% to 20% compared to 3% system average growth. The area surrounding the future Toyota manufacturing plant in the southern part of the city will also grow at a rapid rate with predictions of about 20% annual increase at least for the next few years.

The existing 138-kV tie line that runs from the CPS-owned Helotes substation to LCRA's CICO substation was recently rebuilt and placed in service. This was done in order to support future load growth in the Fair Oaks Ranch area. Fair Oaks Ranch is a CPS substation, located in the northern part of the CPS service area, connected to LCRA's transmission system. The rating on the Helotes–CICO line was doubled, from 215 MVA to 430 MVA. This increased export capability on the line and provides greater voltage support to the Fair Oaks area.

In 2004 approximately 185 MW of new CPS-owned generation will come online at the existing Leon Creek plant. This generation will be used primarily to serve CPS native load and will replace the Mission Road generation plant that will retire in December 2003. The CPS-owned portion of the existing 138-kV tie line from Leon Creek to AEP Texas Central Pleasanton substation was rebuilt and placed in service in June 2003. This transmission line has been a limiting element for exporting power from the CPS system for some time. The CPS portion of the line was reconductored in order to increase the rating of the line, as well as increase reliability. The reconductored portion of the line is now rated at 215 MVA. The remainder of the line is still rated at 101 MVA. The additional generation at Leon Creek in 2004 will further increase the problems of line loading on this circuit.

The LCRA electric system is experiencing rapid load growth in the Guadalupe county service area. As a result, LCRA's Weiderstein Road substation will be located in Guadalupe county near the Weiderstein Road intersection with the CPS transmission line from Skyline to Randolph. CPS will design, construct, own, and maintain the 138-kV transmission line and cut-in modifications. CPS will also provide protective relaying requirements for the interconnection and will make the necessary modifications at its Skyline and Randolph substations to accommodate the interconnection. The planned completion date for this project is January 2004.

Toyota recently chose San Antonio to be the location of a large automobile manufacturing facility. The location will be in the southern region of the CPS service boundary and is expected to begin operation in 2005. This will place a large demand for power in the southern area of the CPS transmission system. Additional customer growth is expected nearby due to the introduction of the plant, and this will increase electric demand even further. CPS will design, construct, own, and maintain a new substation to serve this load for Toyota.

Major Transmission Projects

The LCRA and CPS systems are experiencing load growth in the Kendall and northwest Bexar county areas. This growth has created thermal and voltage problems. To alleviate the problem a second 345/138-kV autotransformer at the Kendall substation was added in 2005, and a new 345-kV transmission tie line between the CPS Cagnon substation and the Kendall substation will be installed by June 2006. Voltage violations of the planning criteria evaluated in 2002 identified the need to relocate a 15.6-Mvar capacitor bank from the New Berlin substation to the LaVernia substation

in Wilson County. In 2003 LCRA installed a 31.2-Mvar capacitor at the 138-kV Boerne substation to provide interim support until these major projects are completed. This project (which included the 345-kV line from Cagnon-Kendall, the second autotransformer at Kendall, and the 31.2- Mvar capacitor bank) was approved by the ERCOT Board of Directors in 2002. Due to changes in system configuration, this study was updated by ERCOT staff July of 2003. Justification for the project was not affected. Possible routes for this project are currently being studied.

Also under study is the addition of a double-circuit 345-kV line between the Clear Springs station (near San Marcos) and Temple. This new line would utilize the proposed S.H.130 right of way. Benefits to this project would include increases in the South to North transfer capability and eliminating the need for a SPS in the San Marcos area. It would also eliminate the need for many 138-kV improvements in the Austin area. Studies have the line being completed in 2008. Most of this line would be located in the North Region.

A second set of 345-kV improvements being considered would create a new 345-kV corridor in the center of the state. Currently, there are 345-kV corridors between Houston and Dallas and between Austin/San Antonio and Dallas. The possible addition would connect Coleto Creek and Holman (90 miles) and Salem and Twin Oaks (110 miles) between the existing corridors. The addition could serve several purposes: a second 345-kV source for the Bryan-College Station area, reduced South to Houston CSC flows, reduced North to Houston CSC flows, and reduced Sandow to Temple CSC flows.

As mentioned in the Laredo section, a 345-kV extension from San Miguel-Laredo-Frontera Power Station is also being considered. This 345-kV extension, while very long and costly, would solve several problems and eliminate the need for RMR contracts in Laredo and the lower Rio Grande Valley and increase the import and export capability of the Valley. It would also help alleviate stability issues associated with serving load in the electrically distant Valley.

The addition of 345-kV lines is also being considered in addressing the fundamental problems underlying Houston import limitations. Whether imported power originates in the north or south, there is a lack of adequate 345-kV tie lines to support economic transfers into Houston. The problem is exacerbated when existing 345-kV tie lines must be taken out of service for maintenance or other reasons. Some preliminary studies have shown that a double-circuit 345-kV tie line from central Texas to west Houston would help relieve congestion into Houston from both the south and the north, as well as reduce South to North CSC congestion. A possible location would be between Fayetteville, Holman, or Salem and either Obrien or a location where lines to Gibbons Creek and Jewett converge (commonly referred to as "Zenith").

An upgrade of the Houston to Dallas corridor with a 765-kV line from STP to Roans Prairie has also been proposed. The purpose of the 765-kV alternative would be to balance power flows between the two existing 345-kV corridors to Dallas and bypass Houston for power flows to and from South Texas.

Up to 600 MW of asynchronous interconnections with Mexico are currently being studied as recommended by the PUCT Project 20948 "Investigation of Issues Relating to Open-Access Interconnections Between ERCOT and Mexico." The additions of these asynchronous interconnections with Mexico hold promise for reducing congestion and RMR costs and making the ERCOT system more secure. Proposed locations for these ties have included Brownsville, McAllen, Del Rio, and Laredo. Additional transmission upgrades may be necessary for these proposed facilities to be fully utilized.

ERCOT, along with transmission service providers and other interested market participants, will continue to work to determine appropriate future actions in the South Region. Figure 20 shows the South Region transmission system.

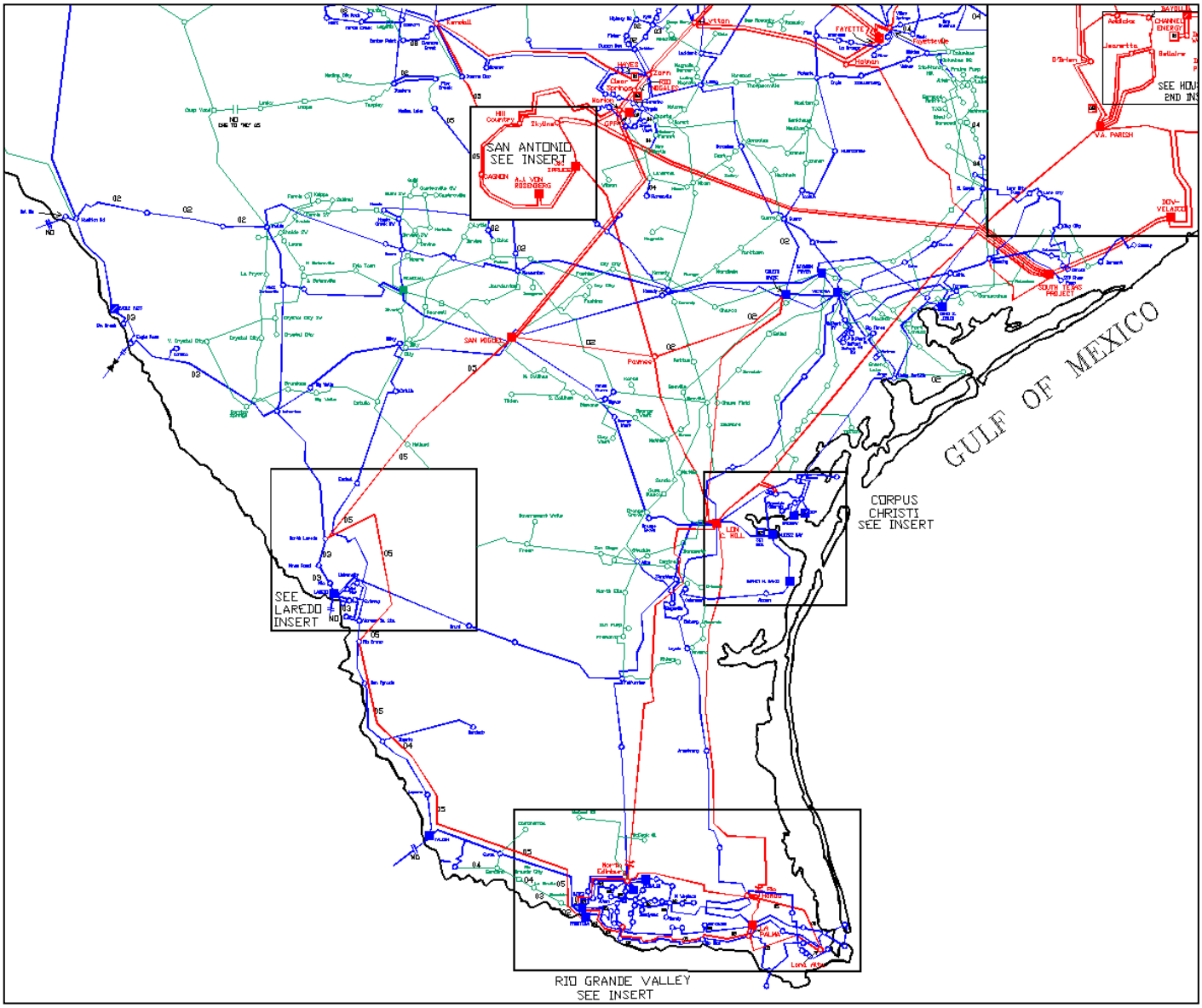

Figure 20 – ERCOT South Region Transmission System

NORTH REGION DISCUSSION

Total load coincident with ERCOT peak in 2002 for the North Region was 27,028 MW. Total generation in the North Region in 2003 is 39,676 MW. The north region has a historical growth rate of 7% between 1997 and 2002 and has a projected load growth of 2.8% between 2004 and 2008. Figure 21 shows the North Region transmission system.

Dallas/Fort Worth Area

The Dallas/Fort Worth (DFW) area includes eight counties - Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Rockwall, and Tarrant. DFW is one of ERCOT's two largest load centers, with a total load coincident with ERCOT peak in 2002 of about 16,428 MW, and has a historical growth rate of 5% over the past five years. DFW load is concentrated inside a four-county metro region (Collin, Dallas, Denton, and Tarrant). The four counties total load in 2002 was 15,068 MW

The eight counties have 9,508 MW of generation. The generation in the four-county metro region totals about 5,800 MW, with the remainder of the generation needed to serve the load imported over the ERCOT transmission grid. Since 1999 about 3,500 MW of generation have been built in the DFW area, and another 2,200 MW of generation are planned near the area, but all these plants are outside the transmission-constrained metro region. "Greenfield" sites for new generation development are limited and are likely to encounter public opposition.

The four-county metro region has been designated by the Environmental Protection Agency (EPA) and the Texas Commission on Environmental Quality (TCEQ) as a non-attainment area for ground-level ozone, which is produced in part from nitrogen oxide (often referred to as "NOx") emissions from burning fossil fuel. The EPA State Implementation Plan (SIP) and Senate Bill 7 mandated specific actions to reduce emissions of NOx from various sources within the area by 2003, with additional reductions required by 2005. To conform to the new mandates, power plants in the metro region are required either to retrofit existing generation units with new NOx reduction devices or to limit operation. Because the existing metro-region transmission system was designed assuming continued operation of this in-region generation capacity, the metro region could experience significant problems of peak period transmission adequacy and voltage stability if a significant amount of the in-region generation becomes unavailable and no new in-region plants or transmission system improvements are built.

ERCOT and the Transmission Service Providers (TSPs) in the metro region have been studying the need for additional 345-kV transmission into the metro region to deliver power from new remote resources constructed in all areas of ERCOT, and enhancements to 345-kV and 138-kV transmission lines and 345/138-kV autotransformer capacity within the metro region assuming a reduction in the usage of generation in the region during peak load periods. Planning for these system improvements is complicated by a lack of information regarding the continued use of existing generation connected to the 138-kV system or redevelopment of these plant sites using newer generation technology.

The TSPs in the DFW area have made the following significant enhancements in 2003 to the transmission system to improve the system's ability to deliver power from remote generators, reduce the dependence on metro-region generation, serve increased load and support voltage:

- Six 345/138-kV autotransformers (3,700 MVA of capacity) were installed before summer peak, and one autotransformer (600 MVA of capacity) is scheduled for installation before the end of the year.
- Oncor has constructed or upgraded 141 circuit miles of 345-kV and 138-kV transmission lines including the Venus–Liggett, Forney–Centerville Switch and Anna–Collin 345-kV lines. Brazos Electric Power Cooperative (BEC) has upgraded 6 circuit miles of the 138-kV line from Coppell to Lewisville.
- Approximately 1,000 Mvar of transmission capacitors were installed to improve voltage support.

By the end of 2003, the TSPs will have approximately 21,000 MVA of 345/138 kV autotransformer capacity installed in the four-county region. This capacity will exceed the projected 2003 load by 3,153 MVA, allowing the transmission system to deliver more power reliably from remote sources to serve customer load and reduce the need to run local generation.

An initial review of actual conditions experienced during summer of 2003 indicates the addition of new generation resources, 345/138-kV autotransformers and transmission capacitors in the eight-county DFW area has improved the voltage on the 345-kV and 138-kV systems.

The TSPs are planning additional improvements to the DFW area's transmission system from 2004 through 2008. Some of the more significant projects are:

- Oncor has seven 345/138-kV autotransformers with a total capacity of 3,500 MVA and BEC has one 700-MVA 345/138-kV autotransformer planned for installation
- Venus–Liggett second 345-kV circuit
- Watermill–West Levee second 345-kV circuit
- West Levee–Norwood 345-kV line
- Watermill–Cedar Hill second 345-kV circuit
- Liggett–Trinity 345-kV line
- Approximately 2,600 Mvar of transmission capacitors

By the end of 2008, the TSPs will have approximately 25,200 MVA of 345/138-kV autotransformer capacity installed in the four-county region. This capacity will exceed the projected 2008 load by 4,112 MVA, allowing the transmission system to deliver more power reliably from remote sources to serve customer load and to reduce the need to run local generation.

Garland is proposing the following projects from 2004 through 2008 to meet system load growth, load switching capabilities, and ERCOT reliability requirements.

- Wynn Joyce to Rosehill line 138-kV impedance change project 05/31/04
- Rosehill to Lyons line 138-kV impedance change project 05/31/04
- Rosehill 138-kV new load-serving substation 05/31/04
- Newman to Miller line 69-kV upgrade project 05/31/04
- Wylie to Firewheel line 138-kV upgrade project 12/31/04
- McCree to Centerville line 69-kV pole change-out project 12/31/04
- Newman to Walnut and Walnut to Castle lines 69-kV insulation interchange project 12/31/04
- Wylie to Ben Davis line 2 138-kV upgrade project 12/31/04
- Walnut to Fairdale line 69-kV upgrade project 12/31/04
- Marquis (Industrial) 138-kV new load-serving substation 05/31/05
- Fairdale to Marquis line 138-kV upgrade project 05/31/05
- Marquis to Shiloh line 138-kV upgrade project 05/31/05
- Wynn Joyce to Miller line 69-kV upgrade project 05/31/05
- Crist Road (North Garland) 138-kV new load-serving substation 05/31/06
- Ben Davis to Crist Road line 138-kV upgrade project 05/31/06
- Crist Road to McCree line 138-kV upgrade project 05/31/06
- Centerville 69-kV to 138-kV substation voltage conversion 05/31/06
- Newman to Walnut 69-kV to 138-kV line voltage conversion project 12/31/06
- Wynn Joyce to Ben Davis line 138-kV upgrade project 12/31/06
- Newman 138-kV new switching station 12/31/06
- Walnut 69-kV to 13- kV substation voltage conversion 12/31/06
- Fairdale load conversion 69-kV to 138-kV project 12/31/06
- Walnut to Fairdale 69-kV to 138-kV line voltage conversion project 12/31/06
- Beltline to Lyons line 138-kV upgrade project 05/31/07
- Beltline to Oates line 138-kV upgrade project 05/31/07
- Beltline 138-kV new load-serving substation 05/31/07
- Brand 138-kV substation upgrade project 05/31/07
- Wynn Joyce to Miller 69-kV to 138-kV line voltage conversion project 12/31/07

- Newman to Miller 69-kV to 138-kV line voltage conversion project 12/31/07
- McCree to Miller line 69-kV upgrade project 12/31/07
- McCree to Miller 69-kV to 138-kV line voltage conversion project 12/31/07
- Oates to Lyons line 138-kV upgrade project 12/31/07
- Miller 69-kV to 138-kV substation voltage conversion 12/31/07
- Walnut to Castle 69-kV to 138-kV line voltage conversion project 05/31/08
- Castle to Naaman line 69-kV upgrade project 05/31/08
- Castle to Naaman 69-kV to 138-kV line voltage conversion project 05/31/08
- Naaman to Apollo line 69-kV upgrade project 05/31/08
- Naaman to Apollo 69-kV to 138-kV line voltage conversion project 05/31/08
- Lookout (Blackburn) 138-kV new load-serving substation 12/31/08
- Firewheel to Lookout line 138-kV upgrade project 12/31/08
- Apollo to Lookout line 138-kV upgrade project 12/31/08
- Olinger to Wylie circuits 138-kV upgrade project 12/31/08
- Castle 69-kV to 138-kV substation voltage conversion 12/31/08
- Naaman 69-kV to 138-kV substation voltage conversion 12/31/08

Two basic scenarios exist for achieving the mandated reduction in NOx emissions and meeting the reliability needs for the four-county metro region. Scenario 1 consists of operating the existing generation in the region out of economic order, upgrading emission controls on the units to reduce NOx, and improving the transmission system assuming this generation will be used. Scenario 2 includes using existing generation in an economic manner with NOx constraints imposed and upgrading the transmission system to support this reduced usage of local generation. The total cost of these scenarios should be compared to determine which one provides the lowest cost to the customers in ERCOT.

The existing 138-kV transmission system in the DFW area is inadequate to handle significant increases in new generation at existing generation sites and must be improved if these sites are redeveloped and the generation capacity is increased.

Construction of new transmission lines in the DFW area is difficult due to the scarcity of suitable routes. Routing and certificating of new lines is a very time-consuming process because of the number of landowners and local governments whose concerns must be addressed. Rebuilding existing lines is complicated by the need to maintain service to the substations connected to these lines and the challenge of obtaining simultaneous construction clearances. Significant progress in providing construction clearances has been made by ERCOT and the Transmission Operators, but the clearances are still a controlling factor in scheduling transmission line and switching station construction.

The load in Denton County has grown from 663 MW in 1997 to 1,373 MW in 2002, which is an annual growth rate of 16%. Load for the area is predicted to grow to 1,830 MW by 2008, an annual growth rate of 5%. Changes of this magnitude obviously present challenges for planning. A few examples illustrate some of the issues to be addressed in the region and some of the complexity and conflicts that can arise when solving one problem results in creating another. If generation in Denton (none of which is owned by the City of Denton) is not online when load is near the summer peak, loss of a single 138/69-kV autotransformer has the potential to cause a voltage collapse on Denton's 69-kV system similar to that seen in Bryan-College Station on April 15, 2003. Work on projects that will resolve this situation, which will include installation of an additional 138/69-kV autotransformer, was initiated over three years ago. Right-of-way issues continue to hold up progress, and the new autotransformer is not expected to be in service before late 2005. Additionally, the loss of certain 345-kV lines, 138-kV single- or double-circuit lines, or 345/138-kV transformers can cause Denton area 138-kV lines to overload if local generation is not online. Recent projects proposed to resolve legitimate contingency overloads in the northern DFW area will exacerbate the contingency overloads of 138-kV lines in the Denton area. In summary, load growth and a planned new 345-kV line from Jacksboro to the Denton West Interchange combined with a reduction in local generation in the SSWG cases are all contributing to the complexity of the operating and planning challenges in the area. Several TSPs are working together to define projects that will resolve all of the contingency overloads and voltage issues in the Denton area.

In order to support energy transfers from outside the DFW area, fully integrate merchant plants, and provide for future service to the DFW area, additional transmission is needed. The transmission providers in the North Texas Region are moving forward with many projects to mitigate these constraints. If proposed projects are completed and placed in service, future studies indicate significant improvement on local constraints in the Dallas/Ft. Worth area. Nevertheless, it appears that large energy transfers south to north, north to south, and west to east will require more bulk 345-kV or higher voltage transmission facilities.

Northeast Texas

The 345-kV transmission system in the northeast portion of ERCOT was originally developed to transport energy from the Valley and Monticello generation facilities to the load in the DFW area. Energy transfers in that area exceeded the original design limits of the 345-kV facilities when the 600-MW East HVDC tie and Tenaska Paris Cogenerator were placed in service.

The installation of the 1,100-MW Lamar Power Project near Paris and the interconnection of the Kiowa Power Partners'(KPP) 1,225-MW plant at Valley have increased the loading on transmission lines connecting the northeast portion of the North Region to the DFW area. With KPP's added generation and with full northeast Texas generation and full import over the EHVDC tie, the Valley-Anna 345-kV line will overload under normal conditions. Several single- and double-circuit contingency conditions will also result in thermal overloading of the 345-kV and/or the 138-kV circuits in the northeast ERCOT area under a more normal dispatch. Outage of the Valley to Paris 345-kV line results in loading beyond rated capacity of the underlying 138-kV system between Paris and Valley.

In 2003, the TSPs completed the following projects to improve the ability of the transmission system in the northeast ERCOT area to accommodate the new generators and deliver power to the metro region:

- Upgrade of the Anna–Collin 345-kV line
- Installation of 138-kV capacitors at Valley
- Modification of a Special Protection System at Valley and enforcement of flow limits on the Valley-Anna and Valley-Farmersville 345-kV lines.

The TSPs are planning additional improvements to the area's transmission system for 2004 through 2008. Some of the more significant projects are:

- Paris–Anna 345-kV line
- Upgrade of Valley–Anna 345-kV line
- Conversion of Paris–Commerce line to 138-kV operation
- Upgrade of Sherman Line Material–Whitesboro Jordan 138-kV line
- Upgrade of Payne-Sherman Line Material–Whitesboro Jordan 138-kV line
- Rebuild of the Anna-Allen Switch 138-kV line
- Rebuild of the Collin-Renner 138-kV line
- Upgrade of the Collin-Bridges-Plano Tennyson 138-kV line
- Installation of the second 345/138-kV autotransformer at Anna

Northwest Portion of North Region

Recently constructed renewable (wind) and merchant generation additions in West Texas have increased the power flow through the northwest part of the region to the rest of the region. Proposed merchant generation located in Jack and Wise counties and additional renewable generation in West Texas will further increase this flow. Studies indicate higher loading on the 345-kV and 138-kV systems under various contingency conditions. The TSPs are proposing to build a Jacksboro Switch–West Denton 345-kV line to address the projected overloads:

South and Central Portions of North Region

Major changes have occurred on the Central Texas system, including significant load growth in Williamson and Travis counties and new generation additions. About 3,000 MW of new merchant generation have been added, and ERCOT has received requests for even more generation interconnection in central portion of the North Region.

Studies of the continuing load growth in the Bryan/College Station area indicate possible voltage problems when generation is out of service in the area. Recent operational experience in the area indicates a need for additional facilities sooner than expected. Installation of a 345/138-kV autotransformer and 138-kV lines into the area would help to support continued service to load. The regional members are currently performing the necessary studies to determine the best solution for the problems.

In 2003 the following projects are to be completed in the central portion of the North Region.

- Jewett–Centerville 138-kV line reconductor
- McNeil–Round Rock–Chief Brady 138-kV line upgrade

Some of the more significant projects planned by TSPs for 2004 through 2008 for this area are as follows:

- Reconductor Copperas Cove–Copperas Cove (LCRA) 138-kV line
- Rebuild Sandow–Minerva–Robertson (BEC) 138-kV line
- Add Killeen Switching Station–Taft Street second 138-kV circuit
- Upgrade Hillsboro–Whitney 138-kV line
- Construct Copperas Cove–Ding Dong (BEC) 138-kV line
- Construct Pecan Creek 345/138-kV switching station and associated lines
- Upgrade Sandow–Temple 345-kV double-circuit line
- Construct Hutto–Salado 345-kV line
- Add a 345/138-kV autotransformer at Hutto switching station
- Upgrade Round Rock-Round Rock Westinghouse 138-kV line
- Upgrade Round Rock-South Round Rock 138-kV line
- Upgrade Walnut Springs-Selden 138-kV line
- Construct Texas A&M to South Switch (BTU) 138-kV line

Brazos Electric is in the process of making extensive improvements to its 69- and 138-kV systems to accommodate new generation, increased load, and changing generation patterns in ERCOT. The following projects are under development or in the planning and internal approval process:

- Transmission to serve new Jack County generation:
- Conversion of the Spring to Jordan 69-kV system to 138 kV
- Upgrade Grandview to Happy Hill 138-kV line
- Upgrade Tintop to Brock 69-kV line to 138 kV operate at 69 kV
- Upgrade Ben Hur to Prairie Hill 69-kV line to 138 kV operate at 69 kV
- Upgrade Ben Hur to Perry 69-kV line to 138 kV operate at 69 kV
- Upgrade Spring to Sanger 138-kV line and install 138-kV switching station at Kruegerville
- Construct new Fairview to Aledo 138-kV line
- Upgrade Peoria to Forreston 69-kV line to 138 kV operate at 69 kV
- Upgrade Spring to St Jo 138-kV line
- Upgrade Powell to Meridian 69-kV line to 138 kV operate at 69 kV
- Upgrade Poage to Leon Junction 69-kV line to 138 kV operate at 69 kV
- Upgrade Whitney to Covington 138-kV line
- Upgrade Prairie Hill to Purdon 69-kV line to 138 kV operate at 69 kV
- Upgrade Olney to Shannon 69-kV line to 138 kV operate at 69 kV
- Upgrade Hilltop Lakes to Hilltop Lakes Switch 69-kV line to 138 kV operate at 69 kV
- Upgrade Hood to Spunky 138-kV line

- Rebuild portion of Gibbons to Steephollow 138-kV line in conjunction with rebuild/conversion of Iola to Booneville 69-kV line (BEC) to College Station switch
- Upgrade Bell County to Taylors Valley 69-kV line to 138 kV operate at 69 kV
- Upgrade Olney to Seymour 69-kV line to 138 kV operate at 69 kV
- Upgrade St Jo to Capps Corner 69-kV line to 138 kV operate at 69 kV

Texas New Mexico Power Company (TNMP) has the following projects scheduled

- 2004 - Loop existing Lake Whitney-Olsen 138-kV line through Bosque Switch
- 2005 - Convert existing Olsen-Jonesboro 69-kV line to 138 kV and install 138/69-kV auto at Jonesboro
- 2006 - Plan to reconductor existing 69-kV line between Olsen and Walnut Springs to 795 ACSR. Specifically, this involves the line that includes these buses: Olsen, Clifton 1, Clifton Tap, Meridian Tap, Walnut Springs

Loads throughout the Central Texas service area have experienced rapid growth over the last eleven years. The total system peak load has increased significantly during this period averaging 5.6% per year The plans developed for the Central Texas area are based on the assumption that a transmission network needs to be in place to serve a peak load of 3,780 MW in the year 2008. This forecast, which corresponds to a 5.7% annual growth rate over the 2,706 MW peak established in 2002, was derived using the substation projections provided by DSPs in the area in 2002. It is comparable to the overall growth trend exhibited since 1980.

Much of the recent growth has been concentrated around the San Antonio and Austin metropolitan areas. Over the next five-year period, it is anticipated that overall load increases exceeding 150 MW will be experienced in Williamson and Hays counties. These county growth patterns tend to indicate that Austin and San Antonio will continue to impact load additions in the service territory. Load growth in the Central Texas area will require that new transmission rights of way and substation sites be acquired over the next five-year period. Some of the more immediately needed transmission rights of way include those in Williamson County (Glasscock to Andice project), Waller County (Macedonia to Hockley project), and Llano County (Sandy Creek to Sunrise Beach project). TSPs are working with county, state, and other officials jointly to plan and develop utility rights of way in these areas.

Potential thermal limitations of the transmission system around the Central Texas area are of particular concern due to the continued high load growth and to the recent additions of over 4,000 MW of generating capacity in this area. In addition, the Central Texas area is also impacted by the generation capacity additions of over 6,000 MW in the South Texas area. To minimize the financial impact, transmission improvements in Central Texas are planned with consideration given to existing transmission corridors and available facilities wherever possible.

Some of the immediately needed transmission improvements and additions in the Central Texas area for which LCRA projects have already been started include the following:

- 2004 - Marion-GPI-Loop 337-Comal 138-kV line upgrade project (ERCOT originated project)
- 2004 - Buda-San Marcos 138-kV line upgrade and conversion project
- 2004 - McNeil-Round Rock 138-kV line upgrade project
- 2006 - Kendall-Cagnon 345-kV line addition (ERCOT Board approved project)
- 2005 - Kendall 345/138-kV, 478-MVA autotransformer addition
- 2005 - Salem 345/138-kV, 672-MVA autotransformer upgrade
- 2005 - Salem-Bellville South 138-kV line upgrades project
- 2004 - Bellville South-Peters 138-kV line upgrade project
- 2004 - Comfort-Verde Creek 138-kV line upgrade project
- 2004 - Hickory Forest–New Berlin 138-kV line addition project (originally operated at 69 kV)
- 2004 - HiCross-Marshall Ford 138-kV line upgrade project
- 2004 - Kendall–Kerrville Stadium 138-kV line upgrade project
- 2005- Kendall-Miller Creek 138-kV line upgrade project
- 2005 - Marshall Ford-Buttercup 138-kV line upgrade project
- 2006 - Comfort-Center Point line upgrade and 69-kV to 138-kV line voltage conversion project

- 2006 - McQueeney-New Berlin line upgrade and 69-kV to 138-kV line voltage conversion project

These projects must remain on schedule to minimize the potential for equipment failures and loss of load.

Transmission line projects identified in this year's update of the long-term plan include:

- 2005- Buchanan-Graphite Mine-Lampasas 138-kV line upgrade
- 2006 - Fayetteville-Pisek-Welcome-Salem 69-kV to 138-kV line voltage conversion
- 2005 - Waller-Prairie View-Seaway-Macedonia 138-kV line upgrade
- 2005 - Uvalde-Camp Wood line upgrade and 69-kV to 138-kV voltage conversion

An alternative, which includes the addition of a 100-mile 345-kV transmission line between Hays County and Bell County (Clear Springs to Salado), is under study by ERCOT and other transmission service providers to address the load growth and new generation capacity added in South and Central Texas.

Stability studies were conducted during 2002 to ensure that area generators can operate in a stable condition after a major transient disturbance. This year's transient stability study indicates that the generators in the area perform in stable conditions after a major transient disturbance. Because of the recent major 345-kV transmission improvements in the Fayette Power Project (FPP) area by the LCRA and Austin Energy to address thermal overload conditions of facilities under contingency conditions, improved critical clearing times were obtained for the FPP units. The transient stability study included eight generating plants and 27 generating units (LCRA and independent power producers). Both single-phase ground and three-phase faults were simulated for each unit. The results indicated the need to adjust breaker failure timers at two generating substations (Wirtz and Sim Gideon), and breaker failure relay settings were issued to address this requirement.

Fault duty studies were conducted during 2002 to ensure that high-voltage circuit breakers throughout the system are appropriately rated to interrupt potential close-in three-phase short circuits. The fault duty study included 125 substations and 477 circuit breakers. Both single-phase ground and three-phase faults were simulated at each circuit breaker. Only one circuit breaker will need to be replaced at the Howard Lane substation.

A bus outage study was conducted during 2002 to review the transmission system performance resulting from the loss of any high-voltage bus in the system. The recommended improved bus designs at four substations (Gillespie, McCarty Lane, Sim Gideon, and Ferguson) will prevent multiple transmission elements (lines, generators, and/or autotransformers) from being lost upon the single-point failure on a high-voltage bus within a substation. These improvements will minimize reliability problems that are projected to occur because of the loss of these buses in the system. Because of this bus outage study, several recommendations to provide improved reliability at these four substations are included in this plan.

Apart from those improvement projects that are required to provide adequate facilities to support continuing load growth and generation capacity additions, plans also include projects that are required to maintain adequate reliability of service and the physical integrity of transmission facilities. Several substations in the system have the potential to lose more than 20 MW during a single contingency. Projects that will solve the largest loss of load events on the system include: a new 138-kV transmission line between the San Bernard Electric Cooperative (SBEC) Macedonia substation and CenterPoint's Hockley substation; a new 3-mile 69-kV transmission line to loop the Kingsland I, Kingsland II, and Sunrise Beach substations; a new 138-kV transmission line between the Andice and Glasscock substations; a new 138-kV transmission line between the Rim Rock and Harper Road substations; a new 138-kV transmission line between the Medina Lake and City Public Service Anderson substations; a new transmission line between the Friendship and the Manchaca substations; a new transmission line between the Highway 32 and Wimberley substations. Circuit breaker additions at in-line substations where peak loads exceed 20 MW are also scheduled over the next five-year period. The plan also includes two projects that will improve load restoration efforts by installing automatic sectionalizing equipment and fault location equipment at strategic locations throughout the system.

In December 2003, an Austin Energy 300-MW combined-cycle generator is scheduled to be installed at the Sand Hill Power Plant in southeast Travis County. The new generation is needed because the Holly Power Plant will be retired in the next few years. Voltage support at Holly will be provided by installing a 100-Mvar, 138-kV STATCOM in late

2004. In order to operate the new Sand Hill power plant reliably at full output, Austin Energy has planned to complete certain transmission improvements by the end of this year. The improvements include the reconfiguration of mostly existing circuits to create a new AMD to Burleson 138-kV circuit and a new Burleson to Carson Creek 138-kV circuit. A new Grove to Met Center 138-kV line will be constructed, and the de-energized Bergstrom to Kingsbery 69-kV line will be re-energized at 138 kV. Austin Energy also plans to reconductor the existing Bergstrom to Onion Creek 138-kV line to 3,000 amperes. Fault studies performed on a 2005 scenario did not reveal any unanticipated equipment rating concerns. Equipment at Onion Creek and Sand Hill substations is rated at 3,000 amperes, 63 kA (fault duty). Transient stability studies reveal that there is sufficient critical clearing time even after the addition of the new 300-MW generation at Sand Hill.

Austin Energy has plans to build a new 138-kV circuit from Decker Plant to Techridge substation in 2005 to minimize overloads on the Decker to Sprinkle 138-kV and Sprinkle to Dessau 138-kV circuits for the loss of Kingsbery substation bus tie or Kingsbery to Wheless Lane 138-kV or Daffin Gin to Dessau 138-kV or Decker to Ed Bluestein and Decker to Walnut Creek 138-kV double circuit. The new 138-kV circuit may eventually be connected to a new 345/138-kV Harris Branch substation to support the addition of a Harris Branch 138/345-kV autotransformer in 2008, if LCRA builds the Clear Springs to Salado 345-kV line. A 138/345-kV autotransformer at Harris Branch will help maintain voltage support northeast of Austin and protect against 138/345-kV autotransformer overloads.

ERCOT and the transmission service providers are working to determine appropriate future actions to address problems experienced and anticipated with the most efficient solutions. Figure 20 shows the North Region transmission system.

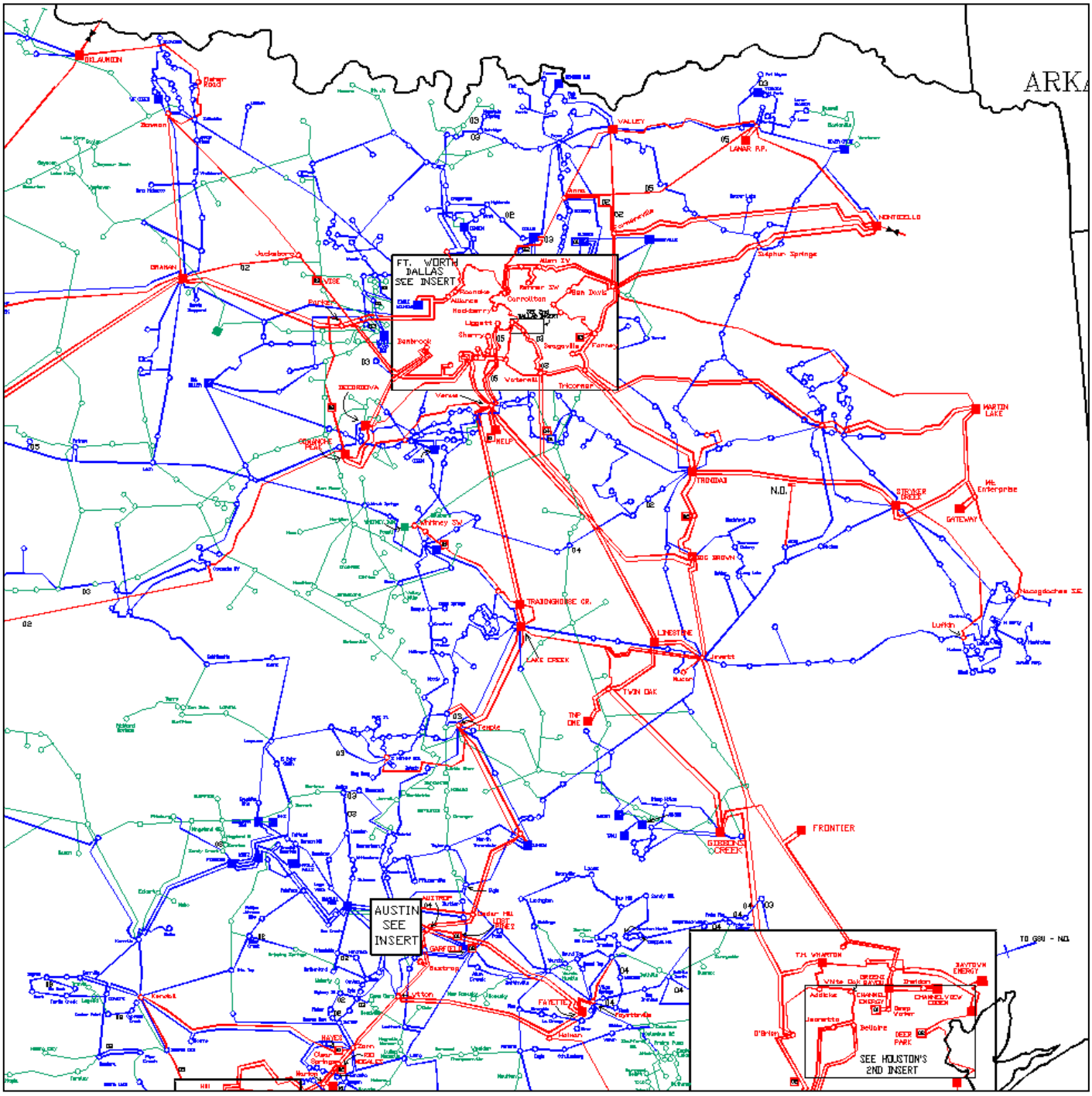

Figure 21 – ERCOT North Region Transmission System

WEST REGION DISCUSSION

The West Region includes Wichita Falls and all of the ERCOT system west of Fort Worth, Waco, and Austin, and northwest of San Antonio and Del Rio. This area is characterized generally by low to no load growth. There are some areas where oil field development is resulting in significant load increases, but these occurrences are infrequent. Most of the transmission construction activity is currently being driven by the development of wind generation and changes in dispatch of existing area gas generation. Though ERCOT has continued to receive numerous interconnection study requests for the area, no new generation has been interconnected in the West Region during the last 12 months.

By 2002, 1,005 MW of wind-powered generation had been added to the area, with 755 MW concentrated near the town of McCamey. The local 138-kV and 69-kV transmission system was not and is presently not capable of delivering full power from all of the McCamey area wind plants to market simultaneously. As a result, severe operating limits have been and are being imposed to protect transmission facilities and reliability of the system. In 2002 and the first half of 2003 no new wind farms were connected but transmission improvement plans were studied, compared, debated, and approved.

One result of the McCamey-area restrictions is that wind developers are again looking elsewhere. In 2003, interconnection agreements for 197.5 MW of wind generation were signed. This generation is to be online by the end of the year and is located outside of the restricted McCamey area.

In January 2003, the West Texas Regional Planning Group held the first regional planning group meeting that included market stakeholders. The purpose of the meeting was to review the "McCamey Wind Generation Transmission Improvement Plan" that was revised in December 2002, the "West Texas Bulk Transmission Study," and the "ERCOT Wind Generation Stability Model." This meeting marked the beginning of a more open ERCOT transmission planning process by soliciting input and comment from stakeholders, such as generation developers and retail electric providers. A second West Texas Regional Planning Group meeting with stakeholders was held in May 2003, and future meetings will be held every six to nine months.

In May 2003 the ERCOT Board of Directors approved the McCamey Area Transmission Plan. This plan endorses the completion of significant upgrades and additions to the 138-kV transmission system in the McCamey area that will allow the export of approximately 1,000 MW of wind generation. In order to maximize the capacity of the 138-kV transmission system, a real-time conductor rating system will provide immediate but limited relief for some limits on wind generation. If necessary, the export of approximately 1,200 MW of wind generation could be accomplished with the installation of special protection systems. To accommodate generation up to 1,500 MW in the McCamey area, the plan also includes a proposed 345-kV line from McCamey to the Twin Buttes substation near San Angelo. Studies and routing analysis for this line have begun and construction would be initiated once interconnection agreements have been signed totaling 1,500 MW. Once interconnection agreements have been signed that total 2,000 MW, construction is to commence on a 345-kV line from McCamey to Odessa. This second 345-kV line from McCamey will increase the export of generation to approximately 2,000 MW.

The reliability challenges the area faces are:

- a sparse transmission system developed to serve dispersed light loads, now being called on to handle concentrations of wind generation that far exceed the local load
- lack of controllable reactive resources as existing gas generation is being mothballed and new wind generation is being installed without adequate dynamic reactive capability
- mismatch of local generation and load
- uncertainty about future generation dispatch levels
- voltage and transient stability

Specific operating problems have recently included high voltages during light load, restrictions on the wind-farm generation output, and requiring three fossil plants to generate on RMR contracts.

Improvements in progress:

- Most of the 138-kV and 69-kV system around Rio Pecos and McCamey is being upgraded and reinforced. Full details of the upgrades are available on the ERCOT and AEP websites. Many of these upgrades will be in service by the end of 2003.
- New 345-kV lines from Comanche Switch to Red Creek and from Red Creek to Morgan Creek were energized in June 2003 and are being intermittently switched out of service due to lack of reactive compensation causing high voltages at light load. These lines are rated for at least 1,631 MVA and provide increased transfer capacity to and from the West Region.
- The new 138-kV Fort Lancaster–Friend Ranch line is expected to be energized in June 2005. This circuit will be rated for at least 400 MVA.
- The existing 138-kV South Abilene–Eskota circuit will be upgraded to 214 MVA by the end of 2003.
- The wind turbine dynamic models will be available for use August 15th so the planners can perform valid stability studies.
- RMR fixes:
  - Two 20-Mvar reactors and a 29-Mvar capacitor bank were installed in July 2003 at Rio Pecos substation.
  - A new substation called Bull Wagon and a 345/138-kV autotransformer are proposed to be built in Abilene to relieve the need for Fort Phantom generation.
  - Twin Buttes substation and 345/138-kV autotransformer will relieve the need for San Angelo generation, but are pending the approval of the CCN for the associated double- circuit 138-kV line.

Future Improvements:

- About 200 Mvar of reactor banks are planned for installation by the end of 2004. These reactors will be installed near the 345-kV backbone to reduce or eliminate the need for the system operators to remove 345-kV lines from service to control high voltages at light load. Wherever possible the reactor banks will be installed on autotransformer tertiaries.
- The McCamey–Twin Buttes 345-kV line is contingent on generation interconnection agreements.
- The McCamey–Odessa 345-kV line is contingent on generation interconnection agreements.
- Special protection systems will be installed around McCamey as needed to allow additional wind power export before the 345-kV circuits are built
- Upgrade Midessa-Midland West 138-kV line
- Upgrade Big Spring-Cosden 138-kV line
- Upgrade Odessa EHV-Glenhaven 138-kV line
- Upgrade Odessa EHV-TI 138-kV line

West Texas generation capacity currently exceeds peak load by about 3,000 MW. Exports from West Texas are limited by post-contingency thermal loading limits of multiple 345-kV and 138-kV lines. Any additional new IPP projects or renewable generation will exacerbate the existing limitation. Light load in West Texas also aggravates this constraint. Recently, market dispatch of West Region gas generation indicates that west to north transfer constraints are not currently a problem. However, it is anticipated that this is only a temporary situation, and that additional wind generation installed in the West Region will result in return of congestion, potentially in off-peak hours. Imports to West Texas are limited by a post-contingency instability that could cause separation and/or loss of the generation in West Texas. This condition occurs when load exceeds generation in West Texas and is still likely to occur when generation either is forced out or is offline for maintenance.

There are two paths for wind generation power to flow from the McCamey area to the bulk transmission system. One path extends north through Crane to Odessa, and the other extends east through Big Lake and Ozona to San Angelo. The 345-kV points of termination of these paths are the Odessa EHV station and the proposed Twin Buttes station, respectively. The northern 345-kV transmission line corridor through Odessa currently carries the majority of power out of West Texas. The proposed 345-kV lines to Twin Buttes and Odessa EHV have been approved contingent on additional generation interconnection agreements.

Service to load in the Brownwood/Comanche/Dublin area is provided via the Stephenville to Dublin 138-kV line and the Comanche Peak–Comanche Switch 345-kV radial line. A contingency outage of either of these lines during a maintenance outage of the other line will result in a loss of service to this area. This problem has been resolved by the completion of the Morgan Creek to Red Creek to Comanche Switch 345-kV line that was energized in June 2003. Installation of a 138-kV circuit between Brownwood Switch and Santa Anna will further strengthen the area in 2004. The Morgan Creek to Red Creek to Comanche Switch 345-kV line, once it is terminated into the new Twin Buttes 345/138-kV station, will provide support for the Concho Valley and San Angelo area. With completion of the Twin Buttes station and the associated 138-kV interconnection into the local 138-kV grid, the area will be supported by the 345-kV system at two locations, relieving the need for support from local generation.

Several alternatives have been evaluated to transfer power out of West Texas. The alternatives included 345-kV, 765-kV, and HVDC alternatives. The regional planning group selected four of the best performing alternatives for further study. The four alternatives were ranked based on their ability to eliminate thermal overloads at different import/export levels, for voltage and transient stability performance, and for their contributions to improving reliability. The planning group reduced the list to two alternatives: (1) add a second 345-kV circuit from Morgan Creek to San Angelo and on to Comanche Peak or (2) build a new 765-kV line from Morgan Creek to West Denton. The second circuit addition is the least-cost alternative that provides incremental transfer capability to and from West Texas. The 765-kV alternative would be needed if gigawatts of wind-power generation are sited in the Panhandle or other areas within the region. These alternatives provide the envelope of transmission upgrades that are available to relieve constraints for comparison to anticipated levels of congestion cost, which would otherwise be incurred.

ERCOT, transmission service providers, and market stakeholders are working to determine appropriate future actions. Figure 22 shows the West Region transmission system.

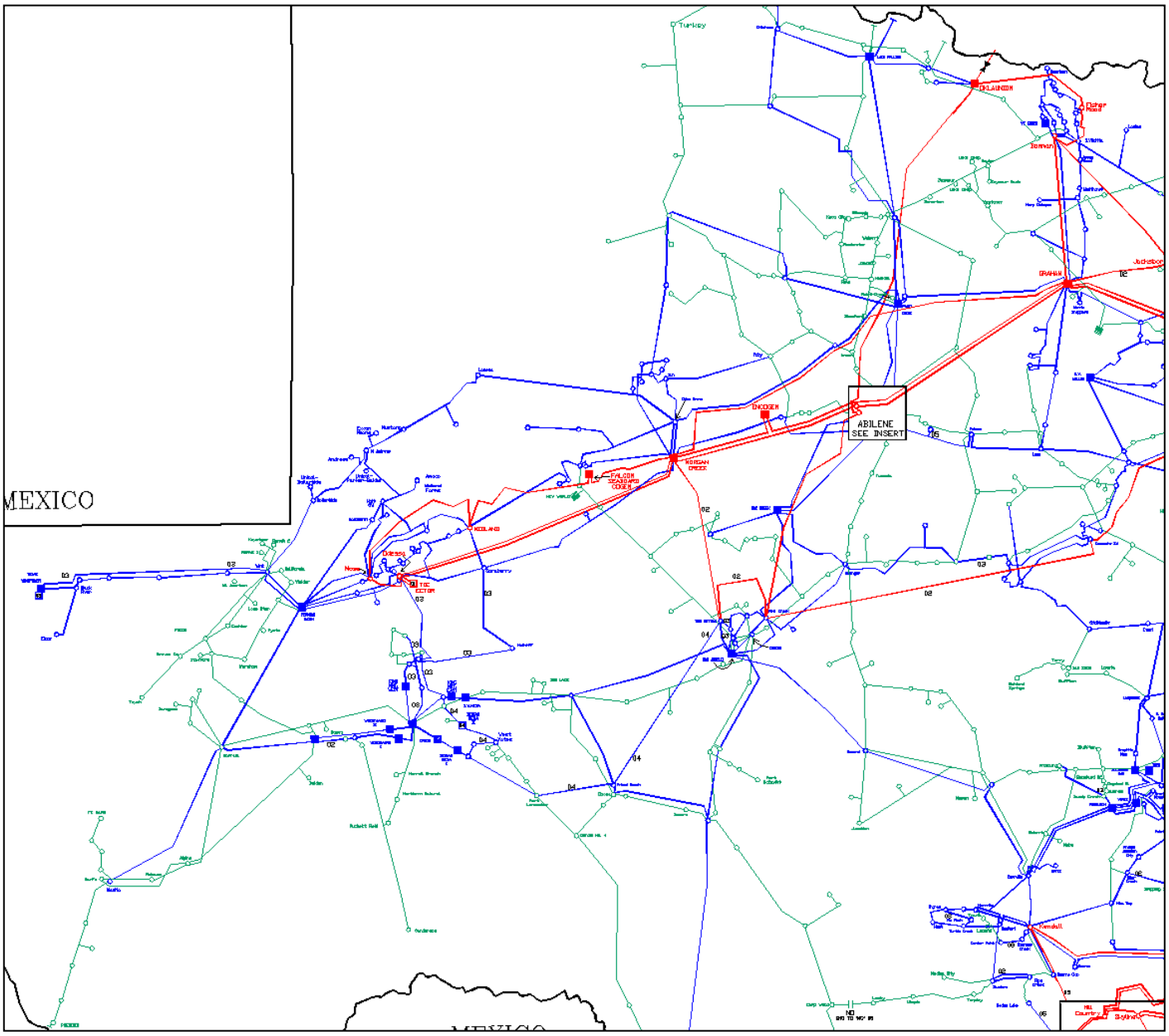

Figure 22 – ERCOT West Region Transmission System

OVERVIEW OF ERCOT LOAD, ENERGY, AND GENERATION

Population

The ERCOT area includes about 200,000 square miles. It is a very diverse area – topographically, climatologically, and demographically. Figure 23 shows a map of Texas with the population projections by county for 2003 (from the Texas Health and Human Services Commission). Approximate ERCOT boundaries are shown on the map.

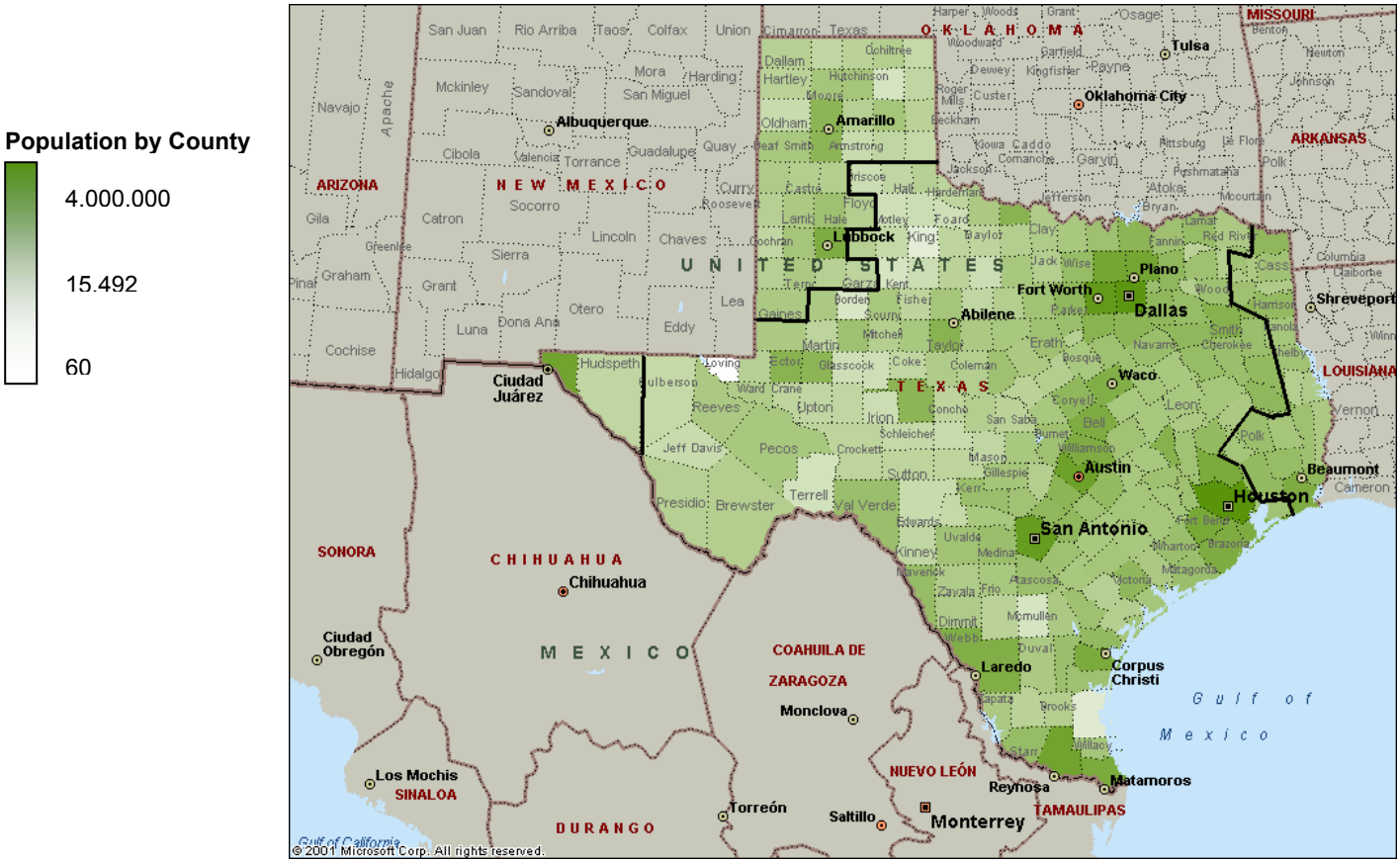

Figure 23 – 2003 Population by County

The counties range in population from Loving County in West Texas with a population of 67 to Harris County in Southeast Texas with a population over 3.5 million. The ten most populous counties in ERCOT are Harris, Dallas, Tarrant, Bexar, Travis, Hidalgo, Collin, Denton, Fort Bend, and Cameron. These counties correspond to the population centers of Houston, the Dallas/Fort Worth metroplex, San Antonio, Austin, and the Valley. The ten least populous counties in ERCOT are Loving, King, Kenedy, Borden, Kent, McMullen, Roberts, Terrell, Motley, and Sterling. These counties are in the Panhandle, West Texas, and South Texas.

Historical Loads

ERCOT represents a bulk electric system located totally within the State of Texas and serves about 85% of the electrical load in the state. Figure 24 shows the monthly peak and minimum demands for the ERCOT system for 2002. Information on ERCOT demands presented herein is from settlements data. The demands are from final and true-up settlements data. The Board of Directors has directed ERCOT to recalculate the true-up settlement based on improved interval meter data to be provided by the TDSPs. These recalculations, other Board directives, and future settlements may change the demands presented herein.

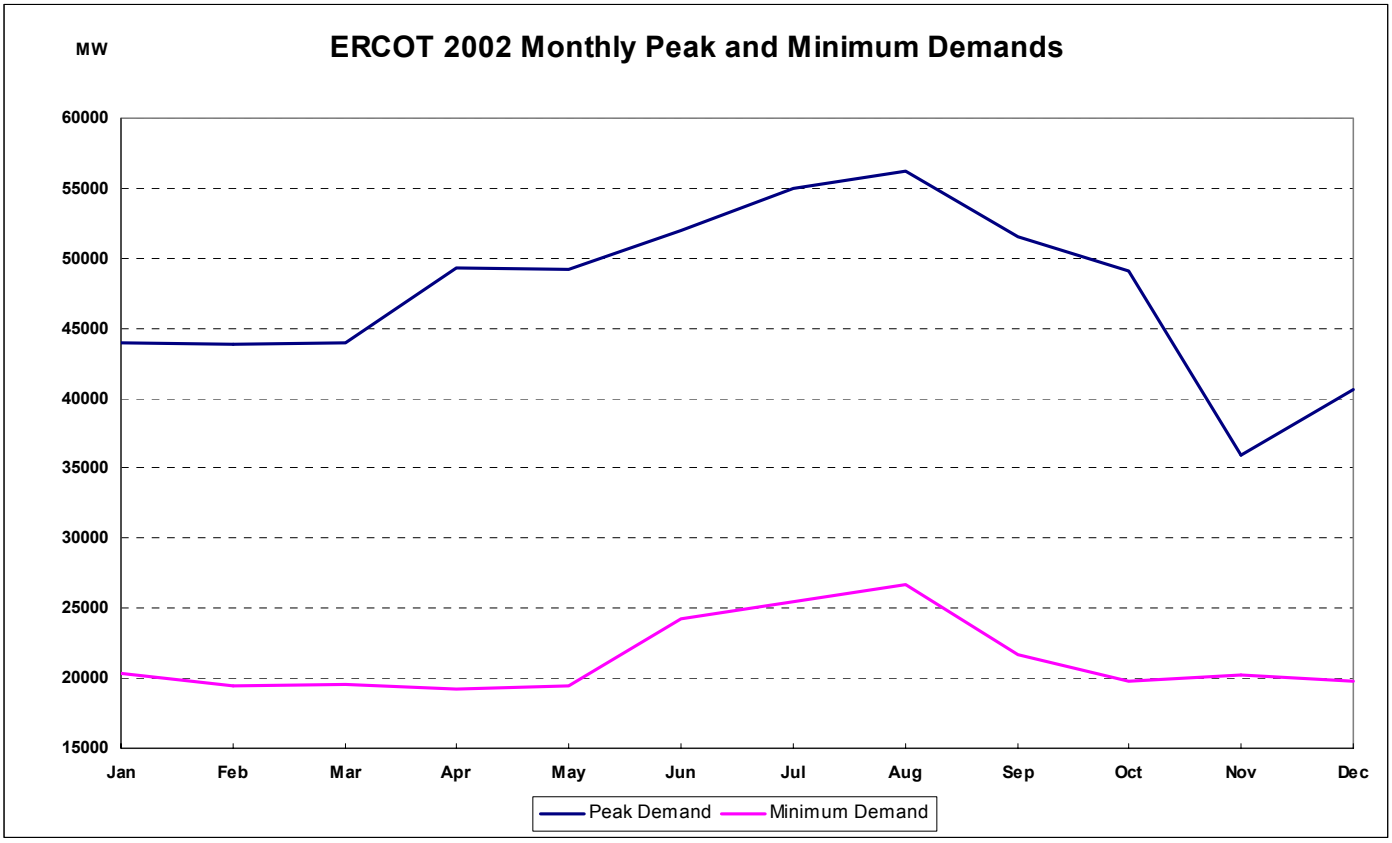

Figure 24 – ERCOT 2002 Monthly Peak and Minimum Demands

It is clear that ERCOT is a summer-peaking system, due to hot weather combined with a high saturation of air conditioning, and usually has the lowest peaks in the spring and fall. When the seasonal peaks in 2002 are compared with the annual peak, the winter peak is 78.1% of the summer peak, the spring peak is 87.6%, and the fall peak is 91.7%. The month with the lowest peak was November, and that peak was 63.8% of the summer peak. Except for the summer months, the minimum demands are around 20,000 MW.

Load duration curves are a good way to get a "big picture" of the system. A load duration curve is the hourly data for a period arranged in decreasing order and plotted against the percent of time in the reference period. Figure 25 shows the load duration curves for the ERCOT system for 1997 and 2002. The loads for 1997 are from data provided by the previous control areas; the loads for 2002 are from ERCOT metering data used in settlements.

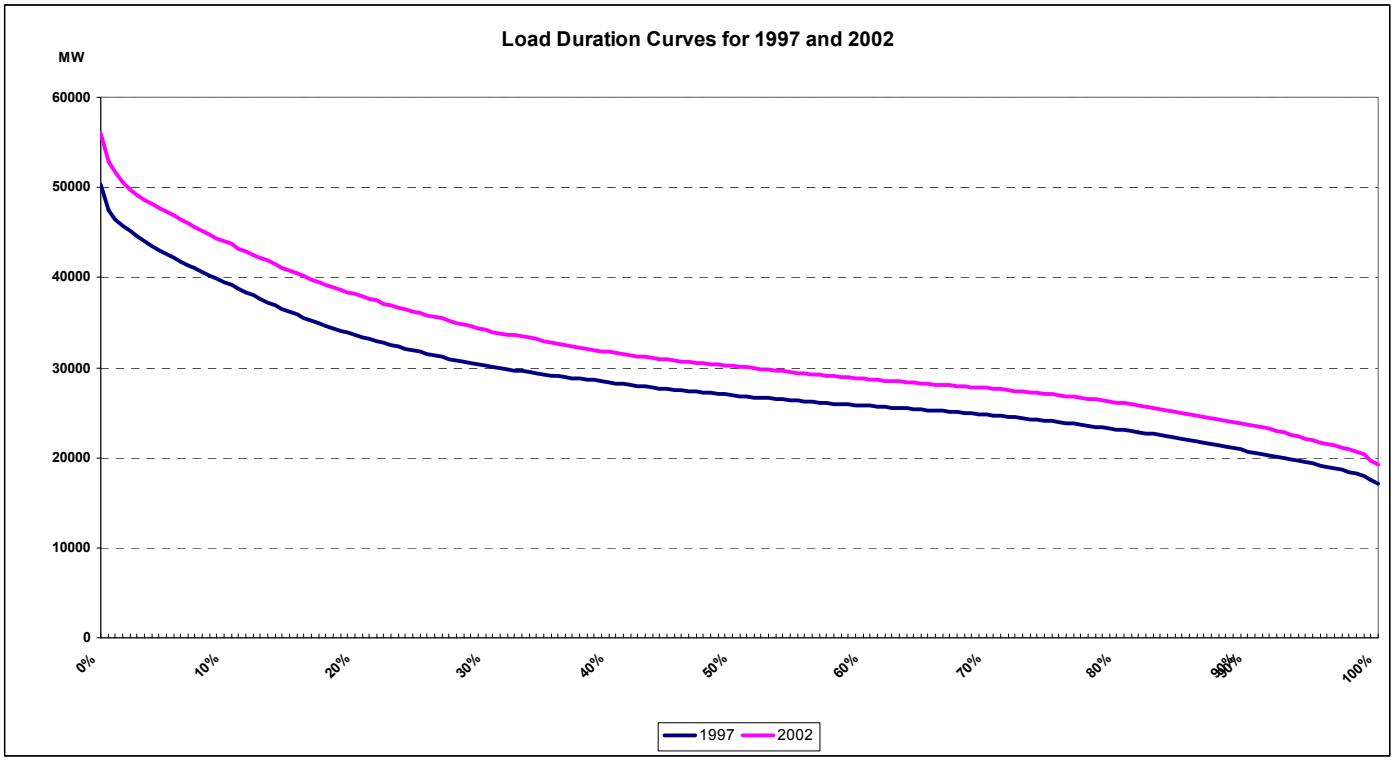

Figure 25 – Load Duration Curves for 1997 and 2002

This graph shows that the shape of the load duration curve has not changed significantly in the last five years. The minimum demand has increased from 17,128 MW in 1997 to 19,266 MW in 2002, a compound growth rate of 2.4%. The maximum demand has increased by a compound growth rate of 2.2%. The energy usage has increased by a compound growth rate of 2.3%.

Load factor is the ratio of the average demand to the peak demand and indicates the variability in electricity demand (the higher the load factor, the less variability of demand in the system). The load factor for the ERCOT area has remained almost constant: 56.6% in 1997 and 56.5% in 2002, but has decreased from 59.2% in 1992. This decrease indicates that there is presently more variability in the ERCOT system than previously.

Peak load can be defined as the load that occurs only 25% of the time. Base load is the minimum constant level of demand that is met at least 85% of the time. Intermediate load is the load that is met between 25% and 85% of the time. The peak and base loads are shown in the load duration curves for 1997 and 2002 in Figures 26 and 27, respectively.

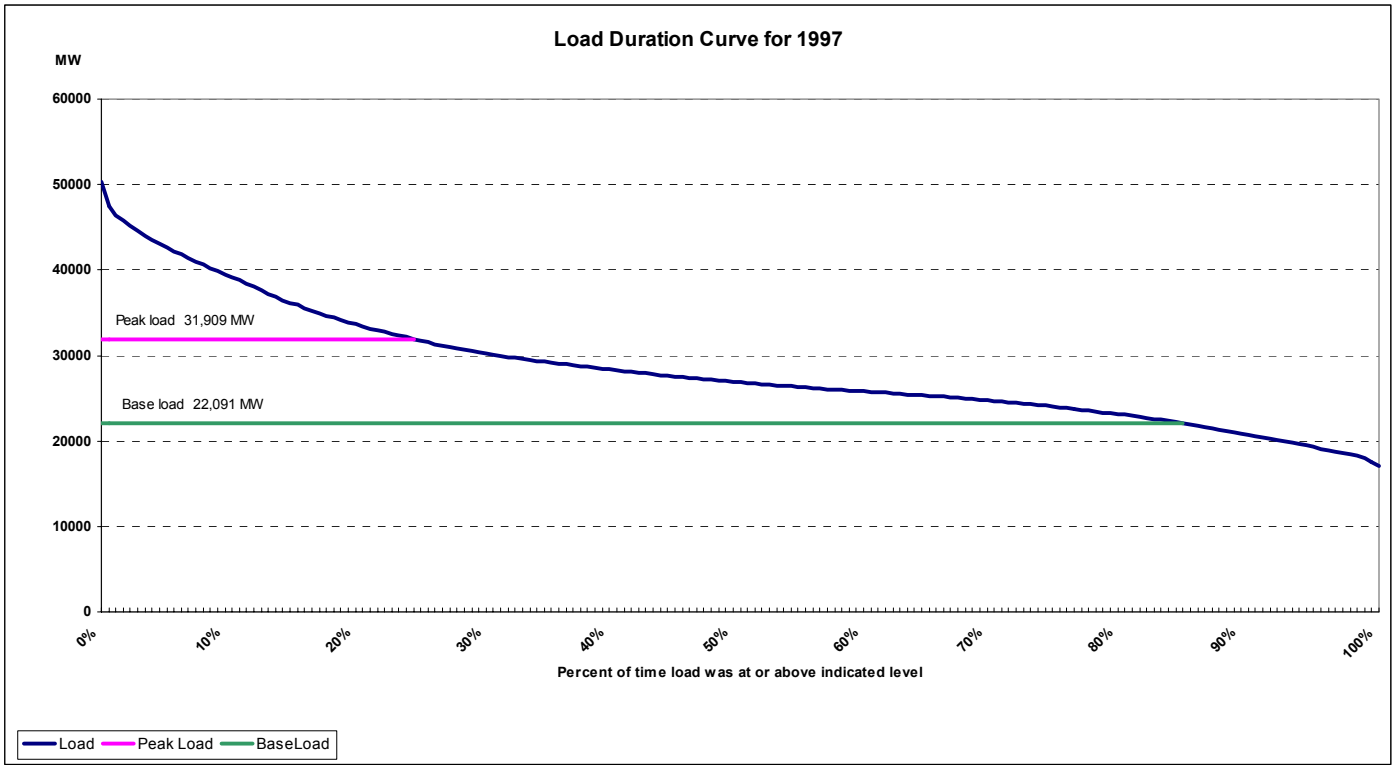

Figure 26 – Load Duration Curve for 1997

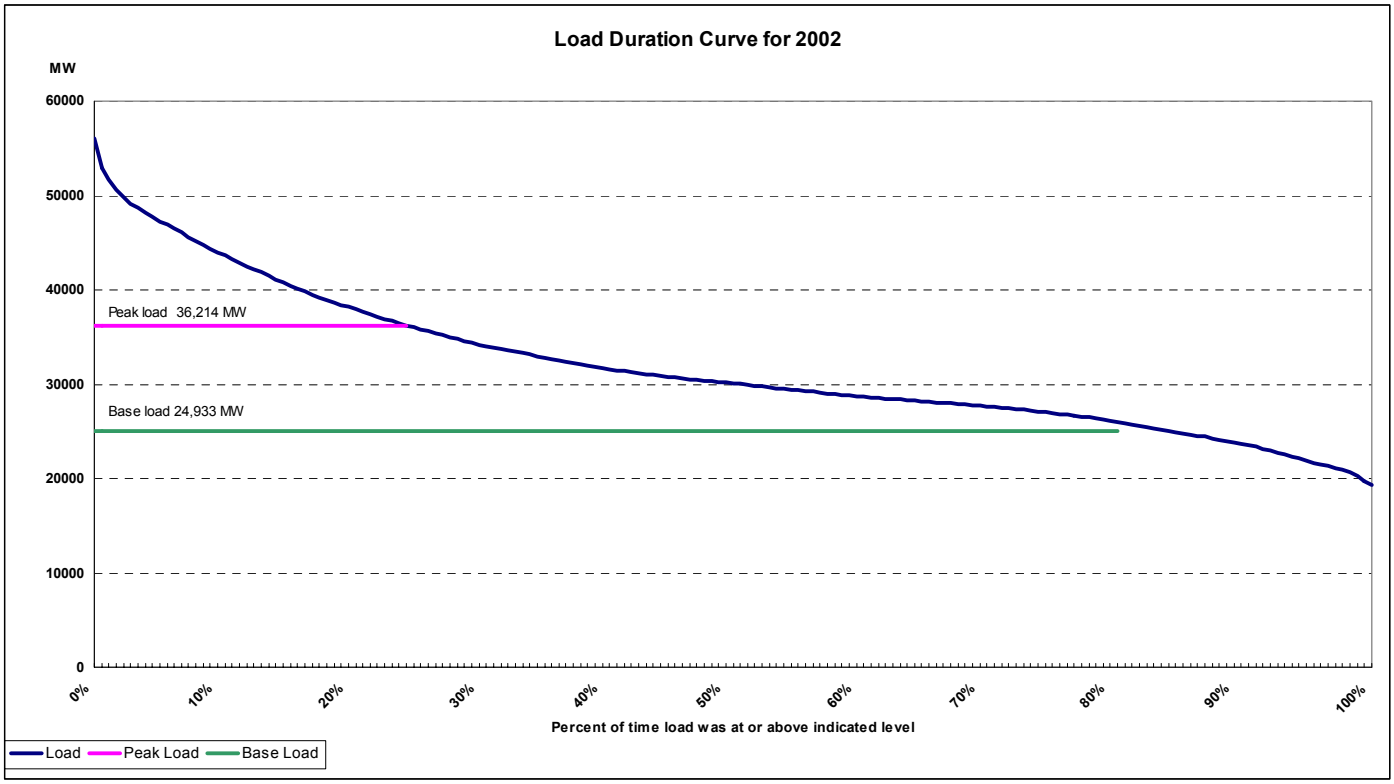

Figure 27 – Load Duration Curve for 2002

The bottom of peak load range increased from 31,909 MW in 1997 to 36,214 MW in 2002, a compound growth rate of 2.6%. The top of the base load range increased from 22,091 MW in 1997 to 24,933 MW in 2002, a compound growth rate of 2.6%. These load growth rates emphasize the importance of maintaining current generating capability and of adding new generation and transmission to the ERCOT system.

Figure 28 shows the ERCOT annual system peak values since 1994 and the annual growth rates. The peak demand for 2003 is based on initial settlement data and may change with future settlements. All other values for 2003 presented herein are forecasted.

YEAR	ERCOT COINCIDENT HOURLY PEAK DEMAND, MW	ANNUAL GROWTH
1994	43,588	-
1995	46,668	7.07%
1996	47,683	2.17%
1997	50,150	5.17%
1998	53,689	7.06%
1999 (1)	54,849	2.16%
2000	57,606	5.03%
2001	55,201	-4.17%
2002	56,248	1.90%
2003 (2)	59,992	6.66%
	Average Nine-Year Compound Growth Rate	3.61%

(1) 1999 value would have been greater if there had been no interruptible load curtailments at the time of the peak.
(2) Peak for 2003 is based on initial settlement data.

Figure 28 – ERCOT Coincident Hourly Peak Demand

Between 1994 and 2003 ERCOT peak demand has grown 37.6% (16,404 MW)..

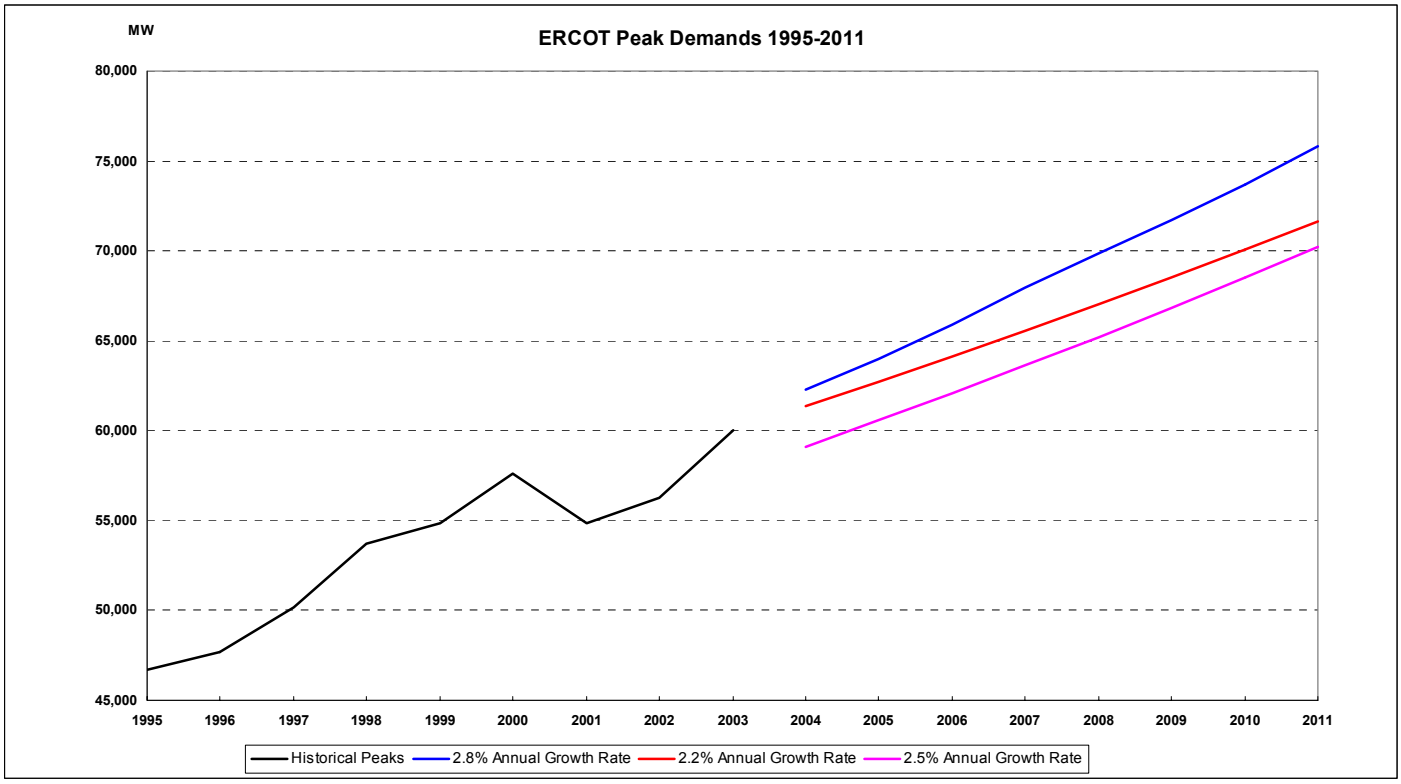

Figure 29 – ERCOT Peak Demands 1995-2011

Figure 29 shows the historical coincident peak demands from 1995 through 2003 and the forecasted peak demands for 2004 through 2011 at three growth rates. The data for 2003 is based on initial settlement data. The 2.8% annual growth rate shows the demands derived from the 2003 ALDR data submitted by the TDSPs. The 2.2% annual growth rate is the actual annual growth rate between 1998 and 2003. The 2.5% growth rate is the growth rate used in the EIA-411 filing. The peak demand has grown considerably since 1995 and is likely to continue to grow.

Location of Demand (Load)

Figure 30 is a map of the ERCOT Region that shows the load by county for the summer of 2003. Note that the loads used in this map are non-coincident peak demand forecasts provided in the 2002 ALDR by the TDSPs.

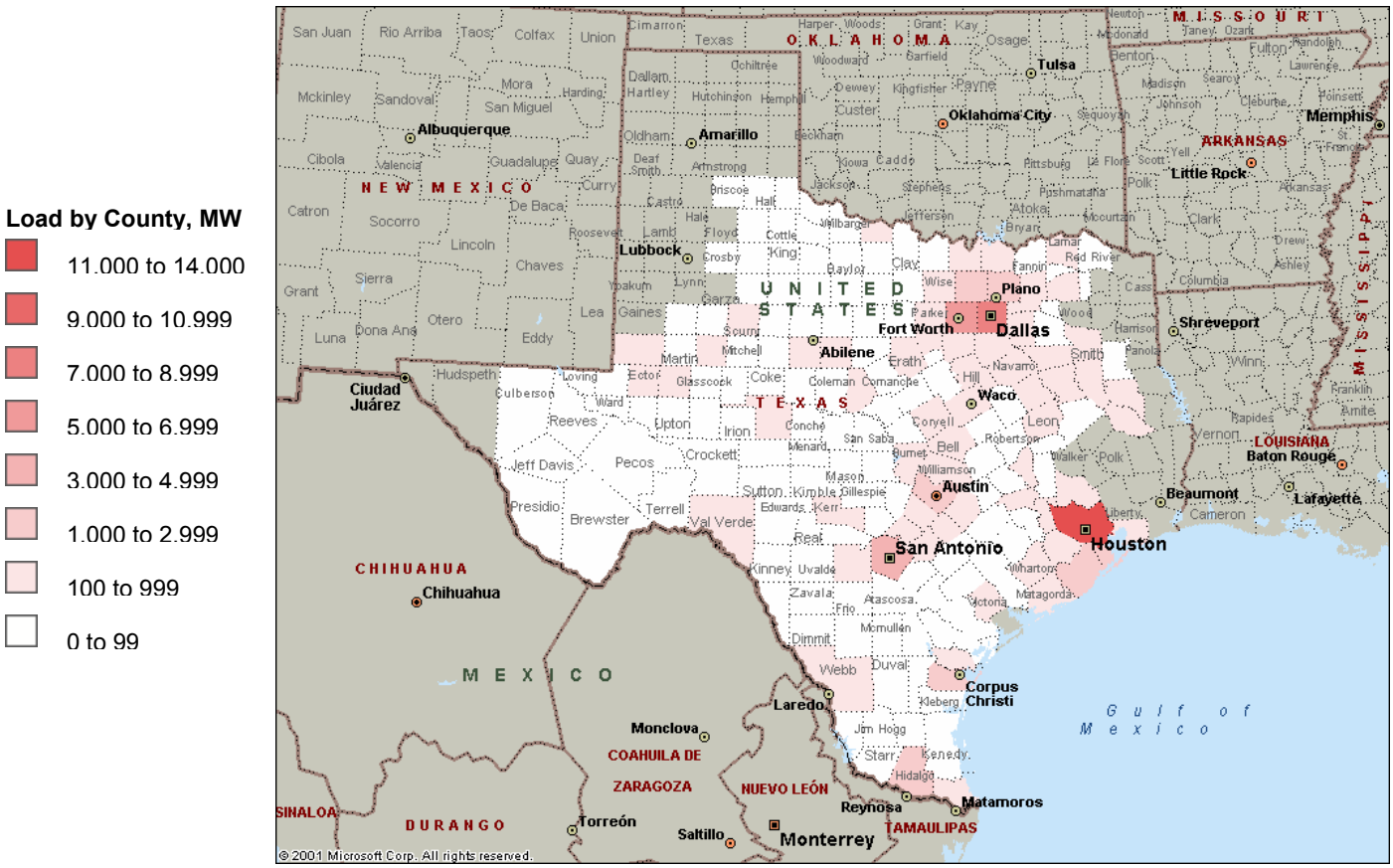

Figure 30 – Peak Demand by County for Year 2003

This figure shows that the greatest peak demand is in Harris County (12,210 MW). The rest of the ten counties with the greatest load are Dallas (8,589 MW), Tarrant (5,405 MW), Bexar (4,292 MW), Travis (2,715 MW), Collin (2,256 MW), Denton (1,597 MW), Brazoria (1,311 MW), Galveston (1,264 MW), and Nueces (1,258 MW). These high-load areas, not surprisingly, correspond to the high-population areas (Figure 23). The ten counties with the least ERCOT load are Kenedy, Borden, Terrell, Hall, Briscoe, Crosby, Rusk, Jeff Davis, Foard, and Franklin; most of these counties are in West and South Texas, where population is lower than in other parts of the state. Franklin County is in East Texas, where the population is greater, but the ERCOT system serves only part of that county.

Figure 31 shows the load growth expected between 2003 and 2008 by county.

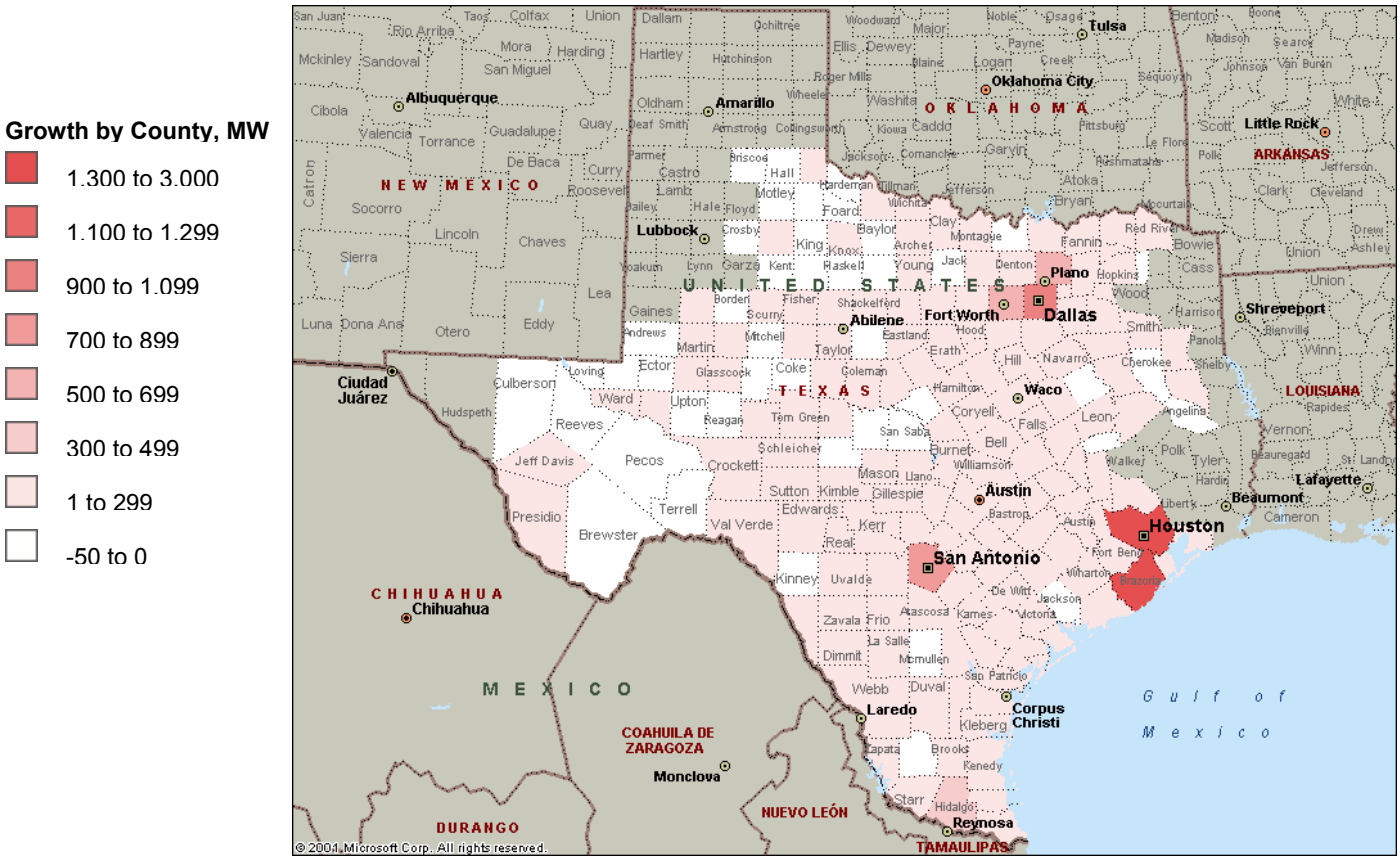

Figure 31 – Load Growth by County Between 2003 and 2008

The counties with the largest expected load growth are Harris, Brazoria, Dallas, Bexar, Collin, Tarrant, Hidalgo, Chambers, Travis, and Williamson. Again, these counties closely correspond to the largest population centers.

Energy Requirement

Figure 32 shows the historical and forecasted annual energy usage in the ERCOT Region. The historical data was derived from the ERCOT Demand and Energy Report. The 2.7% annual growth rate was developed from the 2003 ALDR data. The value for 2003 for this series was interpolated from the values for 2002 and 2004, since 2003 data is not available. The annual energy for 2002 may change with the recalculation of the settlements true-up data mandated by the ERCOT Board of Directors.

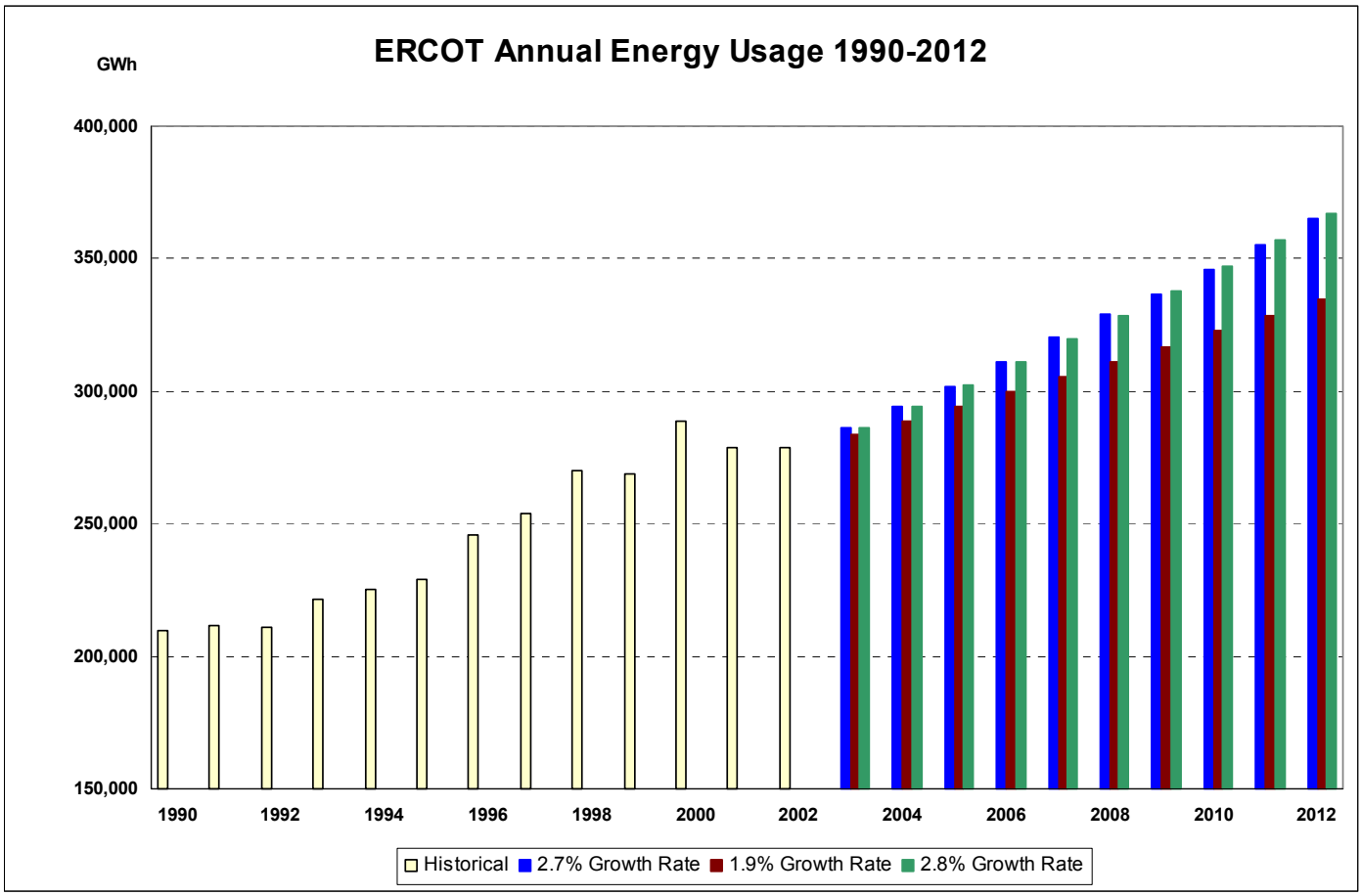

Figure 32 - ERCOT Annual Energy Usage

The 2.8% annual growth rate is the actual growth rate between 1992 and 2002. The 1.9% growth rate is the actual growth rate between 1997 and 2002. The energy usage has increased steadily since 1992 except for 1999, 2001 and 2002. These decreases were due to weather that was more normal in 1999 and in 2001 and 2002 after extremely hot weather in 1998 and 2000.

Location of Generation Capacity

Figure 33 shows a map of the ERCOT Region with the location of the existing generation capacity by county. These values are based on current asset registrations and include switchable capacity (capacity capable of serving both ERCOT and another regional council), DC ties, self-serve generation available for the grid, and distributed generation. The capacities of mothballed units are included in these values.

Generation by County, MW

- 7.000 to 8.000
- 6.000 to 6.999
- 5.000 to 5.999
- 4.000 to 4.999
- 3.000 to 3.999
- 2.000 to 2.999
- 1.000 to 1.999
- 0 to 999

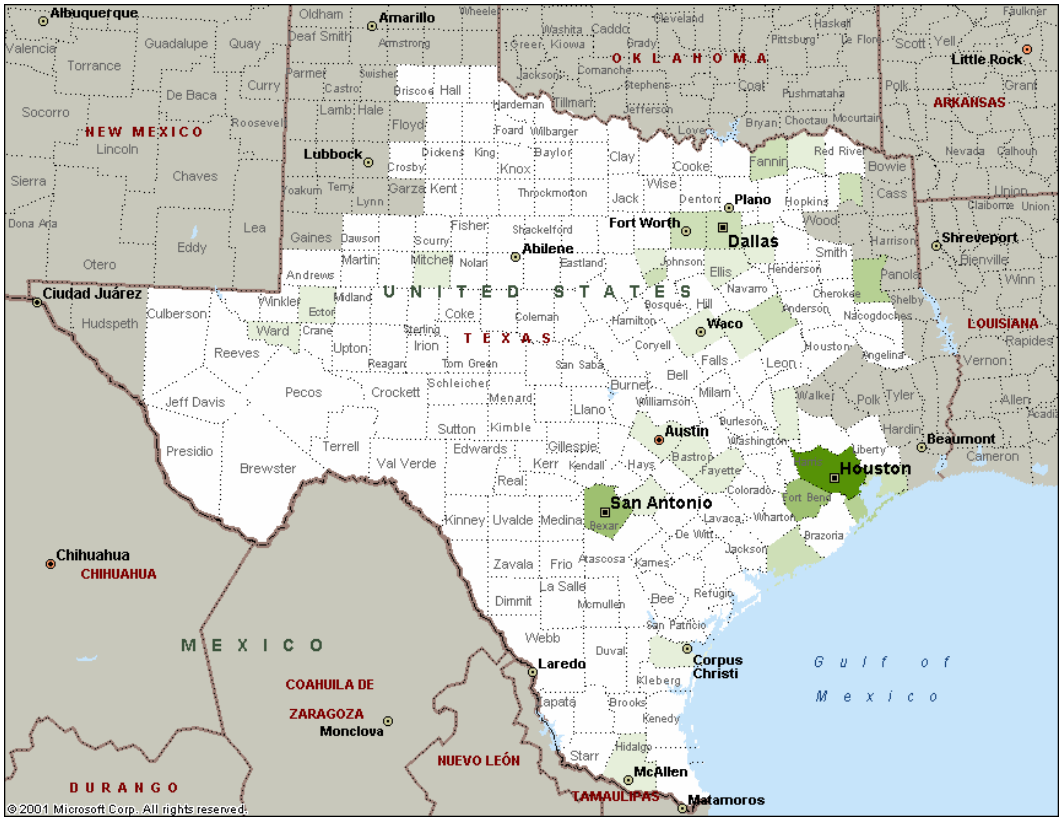

Figure 33 – Generation Capacity by County for the Year 2003

The counties with the greatest amount of capacity are Harris (7,048 MW), Fort Bend (4,439 MW), Bexar (4,311 MW), Galveston (3,375 MW), Rusk (3,115 MW), Dallas (2,913 MW), Chambers (2,797 MW), Matagorda (2,529 MW), Titus (2,475 MW), and Fannin (2,459 MW).

Import/Export

Figure 34 consolidates peak load by county (Figure 30) and generation by county (Figure 33) to show generation import/export by county in the ERCOT system for the year 2003. If a county has more generation than peak load (blue on the map), then it will "export" generation to other counties. If a county has more peak load than generation (red on the map), then it must "import" generation.

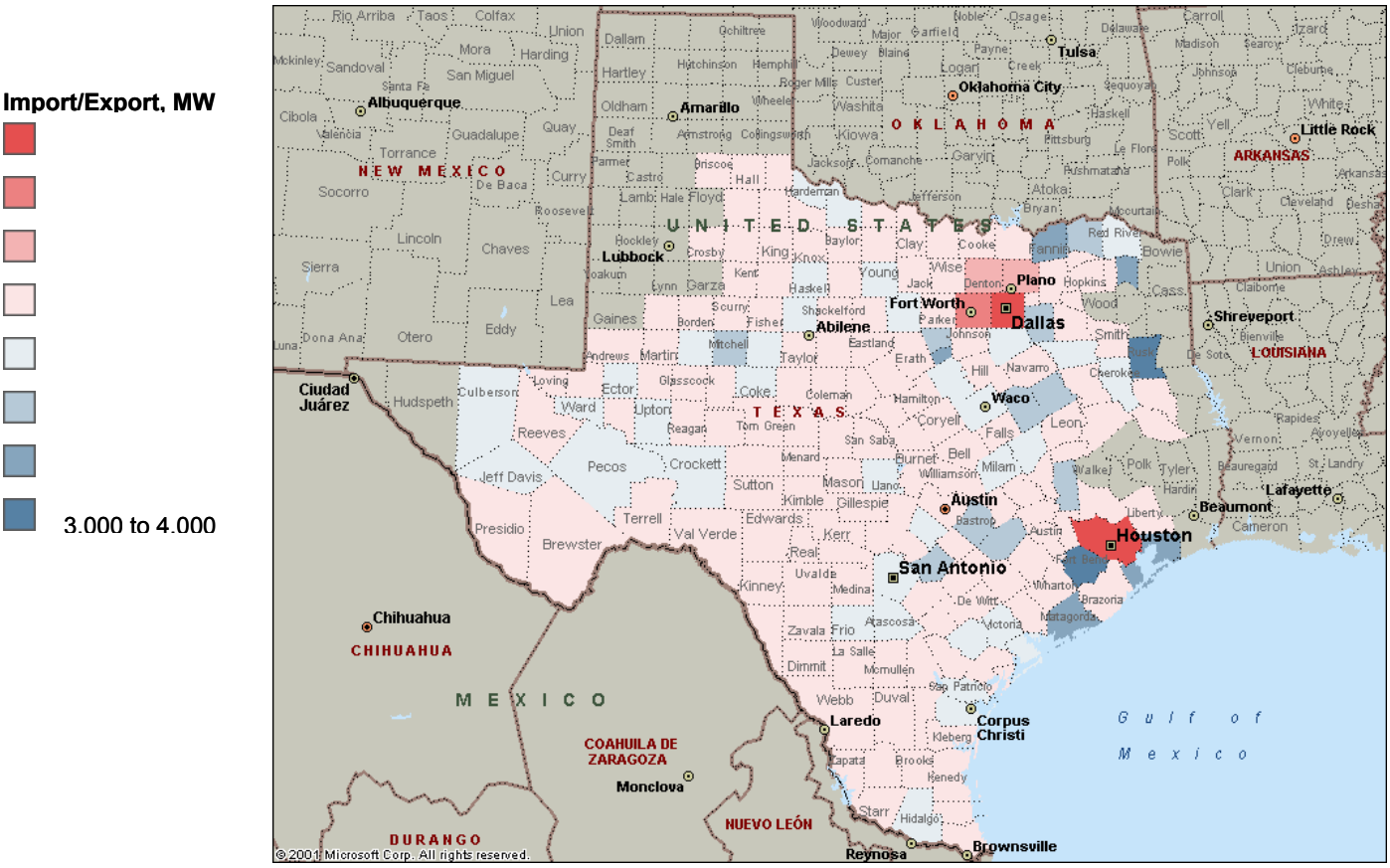

Figure 34 – Generation Import/Export by County for the Year 2003

For the year 2003 for non-coincident peak load, the counties that import the most generation are Dallas, Harris, Tarrant, Collin, Denton, Williamson, Travis, Bell, Brazoria, and Smith. The counties that are able to export the most generation are Fort Bend, Rusk, Titus, Chambers, Fannin, Matagorda, Somervell, Galveston, Freestone, and Hood. The true values will depend on actual load levels and actual generation dispatch.

New Generation Capacity

Since 1997, ERCOT has received more than 182 requests from across the state for generation interconnection. Load growth in the state, the revisions to the PUCT transmission rules, and market deregulation appear to be attracting merchant plant developers to the Texas market. There is still some uncertainty associated with the proposed plants because many are in competition with one another and some may not be built. Figure 35 shows the new generation capacity proposed for the ERCOT system.

In-Service Year	New Proposed Generation Capacity with Interconnection Agreements
2003 (Sep - Dec)	Greater than 700 MW
2004	Greater than 1,900 MW
2005	None
2006	Greater than 2,900 MW

Figure 35 – Proposed Generation Capacity

Proposed new generation may help relieve the current transmission constraints in ERCOT, but, in turn, new generation might worsen the constraints because the existing transmission system cannot fully accommodate the proposed new plants. New generation projects, as well as load growth patterns, direct the need and placement of new transmission additions. The uncertainty of proposed plants and the generation they will displace may result in some imprecise transmission planning at any given time. Therefore, planning for any new transmission additions should provide the capacity above that required for currently identified contingencies.

Figure 36 shows the total generation capacity in the ERCOT Region. The data was derived from the ERCOT System Planning database, which includes all existing units and publicly proposed units with signed interconnection agreements (IA). The proposed plants may not be built and, even if built, their in-service dates and capacities are subject to change. The database includes the capacity and in-service date for most of the existing and new units. Units that are totally dedicated to serving the needs of their own companies (i.e. "self serve") are not included in the discussions in this report. Only capacity available for the grid is included.

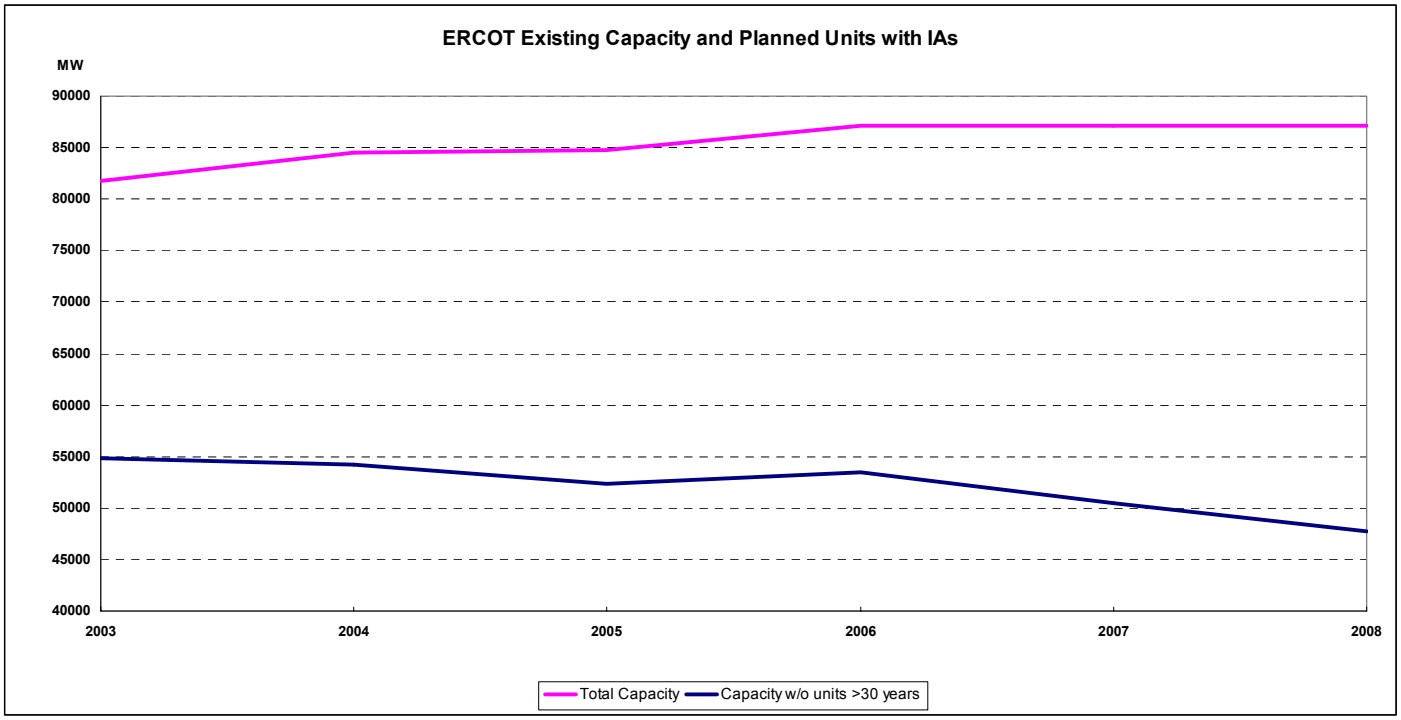

Figure 36 – ERCOT Total Capacity Including Existing Units and Planned Units with Interconnection Agreements

The upper line represents existing capacity plus planned generation that is public and has a signed interconnection agreement. The lower line on the graph reflects the total capacity if all units over 30 years old were retired. Some units will be retired, but age is not the only criterion for retiring a unit.

Changes in Generation

About 5,500 MW of new capacity have been proposed to be added to the ERCOT system between the years 2003 and 2006, and about 400 MW of generation will be retiring by 2005. Figure 37 shows the counties where these changes will occur. This information includes only new generation that is public and has a signed interconnection agreement.

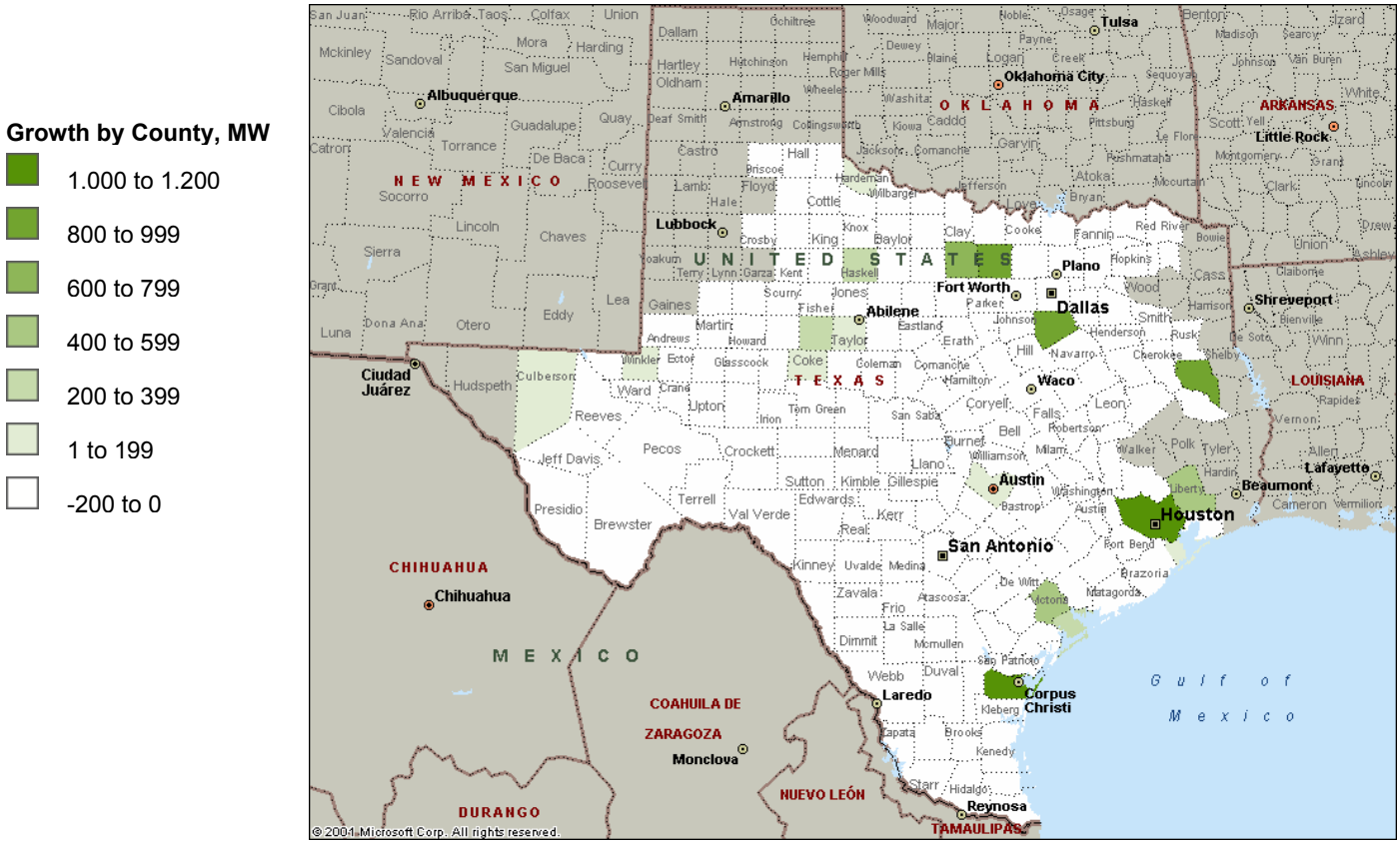

Figure 37 – New Generation Capacity Growth Between 2003 and 2006

The counties with planned new capacity are Harris (1,050 MW), Nacogdoches (954 MW), Ellis (815 MW), Wise (804 MW), Jack (600 MW), Liberty (578 MW), Travis (300 MW), Nolan (200 MW), Culberson (175 MW), Galveston (172 MW), and Winkler (80 MW). The new generation in Ellis, Wise, and Jack counties will likely help provide for the needs of the Dallas/Fort Worth area. The new generation in Harris and Galveston counties will help provide for the needs of the Houston area. The new generation in Liberty and Nacogdoches counties will be capable of serving both ERCOT and Southwest Power Pool (SPP).

In this discussion, counties with the greatest population, peak load, peak load growth, generation capacity, and generation capacity growth have been ranked by magnitude. Figure 38 summarizes this information, showing load growth through 2008 but capacity growth only through 2006 because this is the only data available. It is expected that other generation will be built between 2006 and 2008.

ERCOT TOP TEN COUNTIES BY -				
Population (2003)	**Peak Load (2003)**	**Peak Load Growth (2003-2008)**	**Generation Capacity (2003)**	**Generation Capacity Growth (2003-2006)**
Harris	Harris	Harris	Harris	Harris
Dallas	Dallas	Dallas	Fort Bend	Nacogdoches
Tarrant	Tarrant	Bexar	Bexar	Ellis
Bexar	Bexar	Collin	Galveston	Wise
Travis	Travis	Tarrant	Rusk	Jack
Hidalgo	Collin	Hidalgo	Dallas	Liberty
Collin	Denton	Brazoria	Chambers	Travis
Denton	Brazoria	Chambers	Matagorda	Nolan
Fort Bend	Galveston	Travis	Titus	Culberson
Cameron	Nueces	Williamson	Fannin	Galveston

Figure 38 – Top Ten Counties Ranked in Order

Although Harris County has both the highest load and capacity in 2003, its capacity is considerably less (about 6,000 MW) than its load. Several counties (Fort Bend, Galveston, Chambers) near Harris county have capacity available to supply the load in Harris county. In addition, much of the generation from Matagorda county is used in the Houston area. The transmission system is essential for moving the generation from surrounding counties to Harris county.

It is significant that the county that has the second largest load in 2003 and ranks high in load growth is only sixth in capacity and has no planned new capacity. The counties in the central Dallas/Fort Worth area (Dallas, Tarrant, Collin, Denton) in year 2003 have a combined load of about 17,800 MW but a combined capacity of only about 5,800 MW. Other counties near the DFW area (Hood, Ellis, Grayson, and Somervell) have about 5,800 MW of capacity available for export. Dallas, Tarrant, and Collin counties all are in the top ten for load and load growth, but only Dallas county appears in the top ten for capacity. Collin county ranks sixth in load and fifth in load growth, and Tarrant county ranks third in load and fifth in load growth. Since these counties already have high load and rank very high in load growth between 2003 and 2008, the differential between load and capacity will become even greater. There will be new capacity in Ellis, Jack, and Wise counties to help serve the DFW area. The transmission system will be critically important for delivering power to the Dallas/Fort Worth area.

Future Import/Export

Figure 39 shows the import and export of generation by county for the year 2005. This map was created under the assumption that the proposed new generation that is public and has a signed interconnection agreement is built. It also includes units that have been announced as retiring. The counties that will import the most generation are Harris, Dallas, Tarrant, Brazoria, Collin, Denton, Williamson, Bell, Travis, and Smith. The counties that will have the most generation to export are Fort Bend, Rusk, Titus, Fannin, Matagorda, Chambers, Somervell, Galveston, Freestone, and Hood.

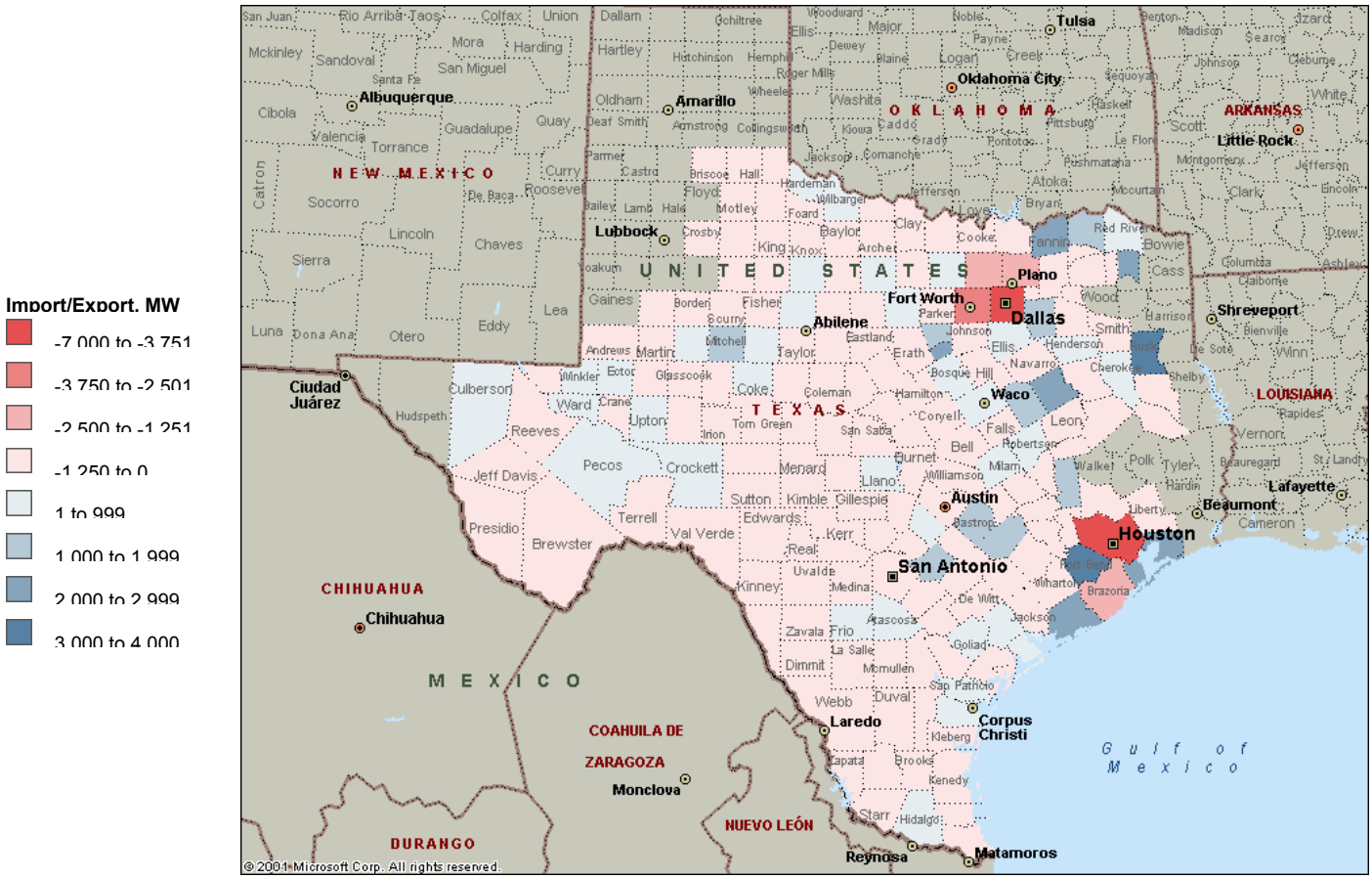

Figure 39 – Generation Import/Export by County for the Year 2005

There are some changes in the import/export of the counties between 2003 and 2005 that are apparent when Figures 34 and 39 are compared. These changes may be small but are sufficient to put some counties into another range of the scale. This discussion includes only those changes visible on the maps. Because of new generation, Freestone County has more generation to export. Because of an increase in load and unit retirements, Bexar County changes from an export county in 2003 to an import county in 2005 by a small amount. Jeff Davis County changes from an export county in 2003 to an import county in 2005. Because of new generation, Winkler and Liberty Counties change from import counties in 2003 to export counties in 2005. Because of an increase in load, Brazoria County must import more in 2005 than in 2003. The true values will depend on actual load levels and actual generation dispatch.

Figure 40 compares the generation capacity import/export by county for 2003 and 2005. Most of the counties remained in the same category relative to importing or exporting but may have changed in relative ranking.

COUNTIES BY GENERATION CAPACITY IMPORT/EXPORT			
IMPORT (2003)	**IMPORT (2005)**	**EXPORT (2003)**	**EXPORT (2005)**
Dallas	Harris	Fort Bend	Fort Bend
Harris	Dallas	Rusk	Rusk
Tarrant	Tarrant	Titus	Titus
Collin	Brazoria	Chambers	Fannin
Denton	Collin	Fannin	Matagorda
Williamson	Denton	Matagorda	Chambers
Travis	Williamson	Somervell	Somervell
Bell	Bell	Galveston	Galveston
Brazoria	Travis	Freestone	Freestone
Smith	Smith	Hood	Hood

Figure 40 – Counties Ranked by Order of Generation Capacity Import/Export

Age of Generating Capacity

One aspect that should be considered in determining available capacity is the age of existing units and whether there will be enough new capacity to compensate for load growth requirements and possible retirement of older units. Few units in the System Planning database have retirement dates. To reflect the possibility of unit retirements, the ages of the units were analyzed by using the in-service dates. The areas used in this analysis are the ERCOT weather zones (Figure 41), and the ages of the plants in those areas were investigated. The results are illustrated in Figure 42.

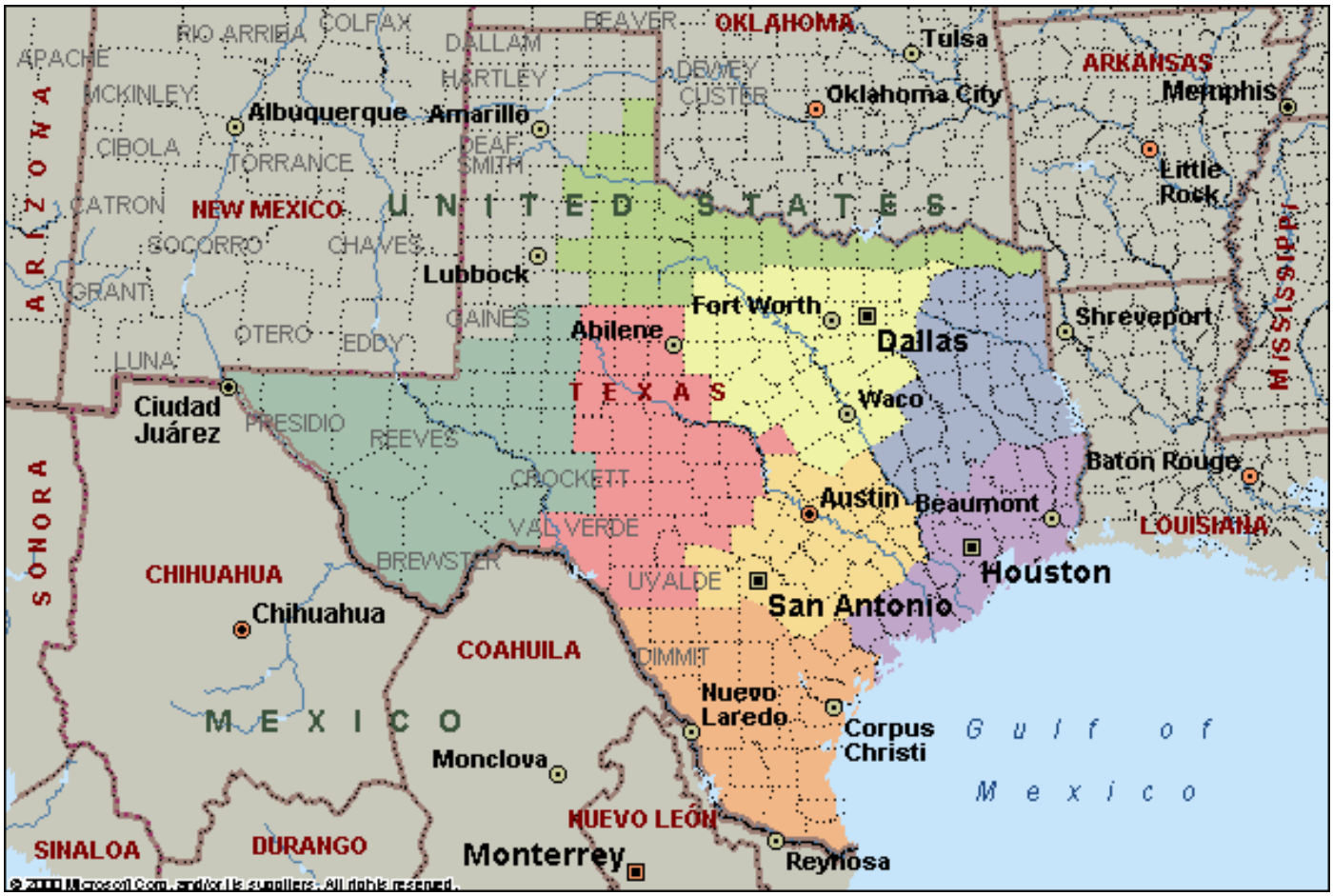

Figure 41 – Areas (ERCOT Weather Zones) Used in Age-of-Plant Analysis

GENERATION CAPACITY BY WEATHER ZONE AND AGES OF PLANTS IN 2003

Weather Zone	Age of Plants				
	> 50	40-49	30-39	20-29	<20
	MW	MW	MW	MW	MW
Coast	165	2,167	6,248	4,570	8,739
East	0	188	1,973	4,718	3,067
Far West	2	158	643	0	2,429
North	106	368	1,054	40	3,327
North Central	536	2,357	4,526	2,114	9,412
South Central	294	720	2,608	3,218	5,752
Southern	136	668	936	1,885	3,000
West	147	338	638	864	854
Total	1,386	6,964	18,626	17,409	36,580

Figure 42 – Generation Capacity by Area and Age of Plants

Most of the capacity greater than 50 years old is in the North Central area, followed by the South Central area of ERCOT. Most of the capacity between 40 and 49 years old is also in the North Central area. Most of the capacity between 20 and 39 years is in the Coast area, followed by the North Central and South Central areas. Older units usually require more maintenance and are generally more expensive to run than newer units.

About 400 MW of generation will be retired by 2005. Most of this generation is in the South Central area.

Figure 43 shows the total generation capacity for summer peaks (including proposed generation projects with interconnection agreements) and plots of the capacity without the older units. The fact that a unit is over 30 year old does not necessarily mean that the unit will retire. Data is not available beyond 2008.

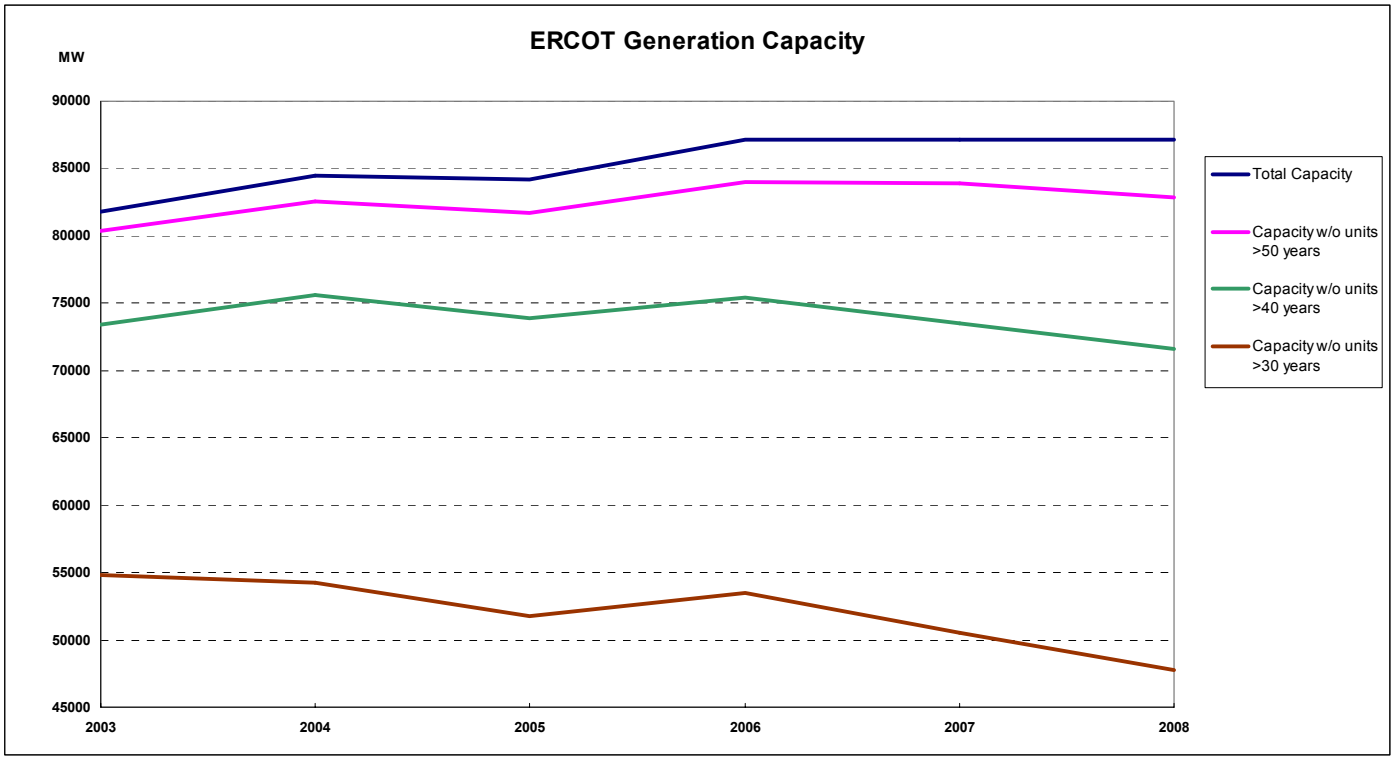

Figure 43 – ERCOT Generation Capacity

Figures 44 and 45 combine the information in Figure 43 with the projected load at various growth rates. Figure 44 reflects the 2.8% annual growth rate, the growth rate from the 2003 ALDRs, and Figure 45 reflects the 2.2% annual growth rate, the actual growth rate between 1998 and 2003.

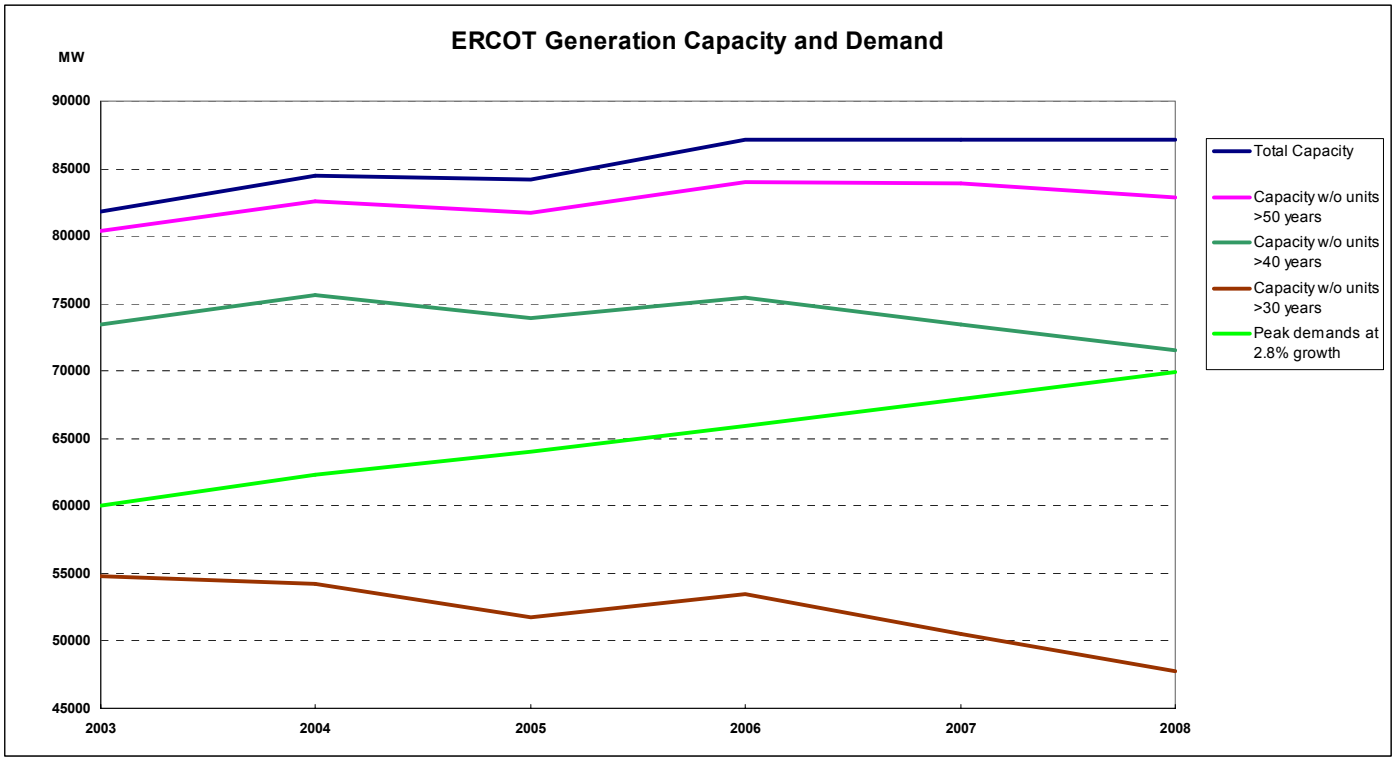

Figure 44 – ERCOT Capacity and Demand (2.8% Annual Growth Rate)

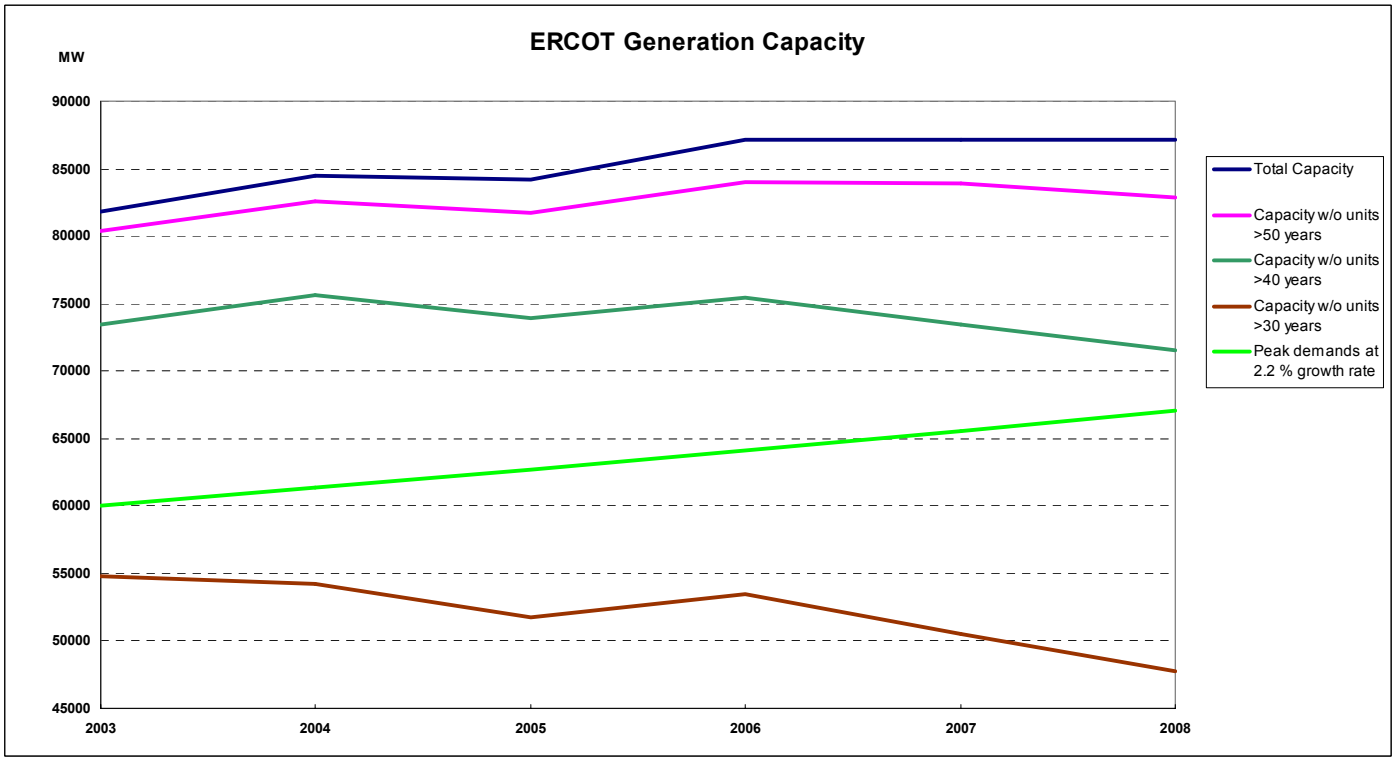

Figure 45 – ERCOT Capacity and Demand (2.2% Annual Growth Rate)

LOAD, ENERGY, AND GENERATION SUMMARY

This overview has presented the historical and forecasted load, energy, and generation in the ERCOT Region. The annual growth rates shown for peak demand range from 2.2% (actual annual growth rate between 1998 and 2003) to 2.8% (the growth rate from the 2003 ALDRs). The capacity includes known planned generation with signed interconnection agreements and potential retirements based on the in-service dates for the units.

The largest load centers do not have corresponding capacity in the immediate area. Both the Dallas/Fort Worth and Houston areas are highly dependent on the transmission system to provide power from surrounding areas in order to serve their loads. As load continues to grow, transmission additions and upgrades will be necessary to continue reliable load service.

DISTRIBUTION CONSTRAINTS

Distribution constraints can affect the consumers' ability to change retail service providers. ERCOT can identify the transmission constraints but is dependent on the distribution service providers for input on distribution constraints. Distribution constraints do not affect the ability of specific generation to serve load but do affect whether or not the load can be served. The configuration of a distribution system (i.e., predominantly a radial system) is such that there are no constraints that are comparable to those on a transmission system. Distribution entities usually monitor and perform a comprehensive analysis of their distribution system during peak load periods. During this analysis of the distribution system, the following areas are analyzed: substation transformer and breaker loading, conductor and line device loading, load balance, steady-state voltage level, short-circuit protection and coordination, service reliability, and system configuration. This analysis is the basis for distribution system improvements that are performed to ensure the continued safe and reliable provision of electric service to customers.

In order to comply with the distribution portion of this report ERCOT requested the assistance of the distribution service providers, load-serving entities, electric power cooperatives, and municipal utilities. Those parties reported no current distribution constraints that would affect their ability to accommodate customers switching among different retail service providers; however, constraints on the distribution system may become a concern because of distributed generation additions being made to the distribution system.