

*The following is the text of Texas SB 7, signed into law by the Governor of Texas on 06/18/1999, and implementing the restructuring of the Texas electricity market. The excerpt below deals specifically with recovery of stranded costs and is provided to the Technical Working Group as a reference. The full text and legislative history for SB 7 is available at:*

<https://capitol.texas.gov/BillLookup/History.aspx?LegSess=76R&Bill=SB7>

SUBCHAPTER F. RECOVERY OF STRANDED COSTS  
THROUGH COMPETITION TRANSITION CHARGE

Sec. 39.251. DEFINITIONS. In this subchapter:

(1) "Above market purchased power costs" means wholesale demand and energy costs that a utility is obligated to pay under an existing purchased power contract to the extent the costs are greater than the purchased power market value.

(2) "Existing purchased power contract" means a purchased power contract in effect on January 1, 1999, including any amendments and revisions to that contract resulting from litigation initiated before January 1, 1999.

(3) "Generation assets" means all assets associated with the production of electricity, including generation plants, electrical interconnections of the generation plant to the transmission system, fuel contracts, fuel transportation contracts, water contracts, lands, surface or subsurface water rights, emissions-related allowances, and gas pipeline interconnections.

(4) "Market value" means, for nonnuclear assets and certain nuclear assets, the value the assets would have if bought and sold in a bona fide third-party transaction or transactions on the open market under Section 39.262(h) or, for certain nuclear assets, as described by Section 39.262(i), the value determined under the method provided by that subsection.

(5) "Purchased power market value" means the value of demand and energy bought and sold in a bona fide third-party transaction or transactions on the open market and determined by using the weighted average costs of the highest three offers from the market for purchase of the demand and energy available under the existing purchased power contracts.

(6) "Retail stranded costs" means that part of net stranded cost associated with the provision of retail service.

(7) "Stranded cost" means the positive excess of the net book value of generation assets over the market value of the assets, taking into account all of the electric utility's generation assets, any above market purchased power costs, and any deferred debit related to a utility's discontinuance of the application of Statement of Financial Accounting Standards No. 71 ("Accounting for the Effects of Certain Types of Regulation") for generation-related assets if required by the provisions of this chapter. For purposes of Section 39.262, book value shall be established as of December 31, 2001, or the date a market value is established through a market valuation method under Section 39.262(h), whichever is earlier, and shall include stranded costs incurred under Section 39.263.

Sec. 39.252. RIGHT TO RECOVER STRANDED COSTS. (a) An electric utility is allowed to recover all of its net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service.

(b)(1) Recovery of retail stranded costs by an electric utility shall be from all existing or future retail customers, including the facilities, premises, and loads of those retail customers, within the utility's geographical certificated service area as it existed on May 1, 1999. A retail customer may not avoid stranded cost recovery charges by switching to new on-site generation except as provided by Section 39.262(k). For purposes of this subchapter, "new on-site generation" means electric generation capacity greater than 10 megawatts capable of being lawfully delivered to the site without use of utility distribution or transmission facilities and which was not, on or before December 31, 1999, either:

(A) a fully operational facility; or

(B) a project supported by substantially complete filings for all necessary site-specific environmental permits under the rules of the Texas Natural Resource Conservation Commission in effect at the time of filing.

(2) If a customer commences taking energy from new on-site generation which materially reduces the customer's use of energy delivered through the utility's facilities, the customer shall pay an amount each month computed by multiplying the output of the on-site generation by the new sum of competition transition charges under Section 39.201 and transition charges under Subchapter G which are in effect during that month. Payment shall be made to the utility, its successors, an assignee, or other collection agent responsible for collecting the competition transition charges and transition charges and shall be collected in addition to the competition transition charges and transition charges applicable to energy actually delivered to the customer through the utility's facilities.

(c) In multiply certificated areas, a retail customer may not avoid stranded cost recovery charges by switching to another electric utility, electric cooperative, or municipally owned utility after May 1, 1999.

A customer in a multiply certificated service area that requested to switch providers on or before May 1, 1999, or was not taking service from an electric utility on May 1, 1999, and does not do so after that date is not responsible for paying retail stranded costs of that utility.

(d) An electric utility shall pursue commercially reasonable means to reduce its potential stranded costs, including good faith attempts to renegotiate above-cost fuel and purchased power contracts or the exercise of normal business practices to protect the value of its assets. The commission shall consider the utility's efforts under this subsection when determining the amount of the utility's stranded costs; provided, however, that nothing in this section authorizes the commission to substitute its judgment for a market valuation of generation assets determined under Sections 39.262(h) and (i).

Sec. 39.253. ALLOCATION OF STRANDED COSTS. (a) Any capital costs incurred by an electric utility to improve air quality under Section 39.263 or 39.264 that are included in a utility's invested capital in accordance with those sections shall be allocated among customer classes as follows:

(1) 50 percent of those costs shall be allocated in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design; and

(2) the remainder shall be allocated on the basis of the energy consumption of the customer classes.

(b) All other retail stranded costs shall be allocated among retail customer classes in accordance with Subsections (c)-(i).

(c) The allocation to the residential class shall be determined by allocating to all customer classes 50 percent of the stranded costs in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design and allocating the remainder of the stranded costs on the basis of the energy consumption of the classes.

(d) After the allocation to the residential class required by Subsection (c) has been calculated, the remaining stranded costs shall be allocated to the remaining customer classes in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design. Non-firm industrial customers shall be allocated stranded costs equal to 150 percent of the amount allocated to that class.

(e) After the allocation to the residential class required by Subsection (c) and the allocation to the nonfirm industrial class required by Subsection (d) have been calculated, the remaining stranded costs shall be allocated to the remaining customer classes in accordance with the methodology used to allocate

the costs of the underlying assets in the electric utility's most recent commission order addressing rate design.

(f) Notwithstanding any other provision of this section, to the extent that the total retail stranded costs, including regulatory assets, of investor-owned utilities exceed \$5 billion on a statewide basis, any stranded costs in excess of \$5 billion shall be allocated among retail customer classes in accordance with the methodology used to allocate the costs of the underlying assets in the electric utility's most recent commission order addressing rate design.

(g) The energy consumption of the customer classes used in Subsections (a)(2) and (c) shall be based on the relevant class characteristics as of May 1, 1999, adjusted for normal weather conditions.

(h) For purposes of this section, "stranded costs" includes regulatory assets.

(i) Except as provided by Section 39.262(k), no customer or customer class may avoid the obligation to pay the amount of stranded costs allocated to that customer class.

Sec. 39.254. USE OF REVENUES FOR UTILITIES WITH STRANDED COSTS. This subchapter provides a number of tools to an electric utility to mitigate stranded costs. Each electric utility that was reported by the commission to have positive "excess costs over market" (ECOM), denoted as the "base case" for the amount of stranded costs before full retail competition in 2002 with respect to its Texas jurisdiction, in the April 1998 Report to the Texas Senate Interim Committee on Electric Utility Restructuring entitled "Potentially Strandable Investment (ECOM) Report: 1998 Update," must use these tools to reduce the net book value of, otherwise referred to as "accelerate" the cost recovery of, its stranded costs each year. Any positive difference under the report required by Section 39.257(b) shall be applied to the net book value of generation assets.

Sec. 39.255. USE OF REVENUES FOR UTILITIES WITH NO STRANDED COSTS. (a) An electric utility that does not have stranded costs described by Section 39.254 shall be permitted to use any positive difference under the report required by Section 39.257(b) on capital expenditures to improve or expand transmission or distribution facilities, or on capital expenditures to improve air quality, as approved by the commission. Any such capital expenditures shall be made in the calendar year immediately following the year for which the report required by Section 39.257 is calculated. The capital expenditures shall be reflected in any future proceeding under this chapter to set transmission or distribution rates as a reduction to the utility's transmission and distribution invested capital, as approved by the commission.

(b) To the extent that positive differences under the report required by Section 39.257(b) are not used for capital expenditures, the amounts shall be flowed back to the electric utility's Texas jurisdictional customers through the power cost recovery factor.

(c) This section applies only to the use of positive differences under the report required by Section 39.257(b) for each year during the freeze period.

Sec. 39.256. OPTION TO REDIRECT DEPRECIATION. (a) For the calendar years of 1998, 1999, 2000, and 2001, an electric utility described by Section 39.254 may redirect all or a part of the depreciation expense relating to transmission and distribution assets to its net generation plant assets.

(b) The electric utility shall report a decision under Subsection (a) to the commission and any other applicable regulatory authority.

(c) Any adjustments made to the book value of transmission and distribution assets or the creation of any related regulatory assets resulting from the redirection under this section shall be accepted and applied by the commission for establishing net invested capital and transmission and distribution rates for retail customers in all future proceedings.

(d) Notwithstanding Subsection (c), the design of post-freeze-period retail rates may not:

- (1) shift the allocation of responsibility for stranded costs;
- (2) include the adjusted costs in wholesale transmission and distribution rates; or
- (3) apply the adjustments for the purpose of establishing net invested capital and

transmission and distribution rates for wholesale customers.

Sec. 39.257. ANNUAL REPORT. (a) Beginning with the 1999 calendar year, each electric utility shall file a report with the commission not later than 90 days after the end of each year during the freeze period under a schedule and a format determined by the commission.

(b) The report shall identify any positive difference between annual revenues, reduced by the amount of annual revenues under Sections 36.203 and 36.205, the revenues received under the interutility billing process as adopted by the commission to implement Sections 35.004, 35.006, and 35.007, revenues associated with transition charges as defined by Section 39.302, and annual costs.

Sec. 39.258. ANNUAL REPORT: DETERMINATION OF ANNUAL COSTS. For the purposes of determining the annual costs in each annual report, the following amounts shall be used:

(1) the lesser of:

(A) the utility's Texas jurisdictional operation and maintenance expense reflected in each utility's Federal Energy Regulatory Commission Form 1 of the report year, plus factoring expenses not included in operation and maintenance, adjusted for:

(i) costs under Sections 36.062, 36.203, and 36.205; and

(ii) revenues recorded under the interutility billing process adopted by the commission to implement Sections 35.004, 35.006, and 35.007; or

(B) the Texas jurisdictional operation and maintenance expense reflected in each utility's 1996 Federal Energy Regulatory Commission Form 1, plus factoring expenses not included in operation and maintenance, adjusted for:

(i) costs under Sections 36.062, 36.203, and 36.205, and not indexed for inflation;

(ii) any difference between the annual revenues and the expenses recorded under the interutility billing process adopted by the commission to implement Sections 35.004, 35.006, and 35.007; and

(iii) the annual percentage change in the average number of utility customers;

(2) the amount of nuclear decommissioning expense approved in the electric utility's last rate proceeding before the commission, as may be required to be adjusted to comply with applicable federal regulatory requirements;

(3) the depreciation rates approved in the electric utility's last rate proceeding before the commission;

(4) the amortization expense approved in the electric utility's last rate proceeding before the commission or in any other proceeding in which deferred costs and the amortization of those costs are established, except that if the items are fully amortized during the freeze period, the expense shall be adjusted accordingly;

(5) taxes and fees, including municipal franchise fees to the extent not included in Subdivision (1), other than federal income taxes, and assessments incurred that year;

(6) federal income tax expense, computed according to the stand-alone methodology and using the actual capital structure and actual cost of debt as of December 31 of the report year;

(7) return on invested capital, computed by multiplying invested capital as of December 31 of the report year, determined as provided by Section 39.259, by the cost of capital approved in the electric utility's most recent rate proceeding before the commission in which the cost of capital was specifically adopted, or, in the case of a range, the midpoint of the range, if the final rate order for the proceeding was issued on or after January 1, 1992, or if such an order does not exist, a cost of capital of 9.6 percent shall be used; and

(8) the amount resulting from any operation and maintenance expense savings tracker from a merger of two utilities and contained in a settlement agreement approved by the commission before January 1, 1999.

Sec. 39.259. ANNUAL REPORT: DETERMINATION OF INVESTED CAPITAL. (a) For the purposes of determining invested capital in each annual report, the net plant in service, regulatory assets, and deferred federal income taxes shall be updated each year, and generation-related invested capital shall be reduced by the amount of securitization under Sections 39.201(i) and 39.262(c) to the extent otherwise included in invested capital.

(b) Capital additions to a plant in an amount less than 1-1/2 percent of the electric utility's net plant in service on December 31, 1998, less plant items previously excluded by the commission, for each of the years 1999 through 2001 are presumed prudent.

(c) All other items in invested capital shall be as approved in the electric utility's last rate proceeding before the commission.

Sec. 39.260. USE OF GENERALLY ACCEPTED ACCOUNTING PRINCIPLES. (a) The definition and identification of invested capital and other terms used in this subchapter and Subchapter G that affect the net book value of generation assets and the treatment of transactions performed under Section 35.035 and other transactions authorized by this title or approved by the regulatory authority that affect the net book value of generation assets during the freeze period shall be treated in accordance with generally accepted accounting principles as modified by regulatory accounting rules generally applicable to utilities.

(b) The principles and criteria described by Subsection (a), including the criteria for applicability of Statement of Financial Accounting Standards No. 71 ("Accounting for the Effects of Certain Types of Regulation"), shall be applied for purposes of this subchapter as they existed on January 1, 1999.

Sec. 39.261. REVIEW OF ANNUAL REPORT. (a) The annual report filed under this subchapter is a public document and shall be reviewed by the staff of the commission and the office. Both staffs may review work papers and supporting documents and engage in discussions with the utility about the data underlying the reports.

(b) The staff of the commission and the office shall communicate in writing to an electric utility not later than the 180th day after the date the report is filed if they have any disagreements with the data or computations.

(c) The commission shall finalize and resolve any disagreements related to the annual report, consistent with the requirements of Section 39.258, as follows:

(1) for each calendar year, the commission shall finalize the annual report before establishing the competition transition charge under Section 39.201; and

(2) for each calendar year, the commission shall finalize the annual report and reflect the result as part of the true-up proceeding under Section 39.262.

Sec. 39.262. TRUE-UP PROCEEDING. (a) An electric utility, together with its affiliated retail electric provider and its affiliated transmission and distribution utility, may not be permitted to overrecover stranded costs through the procedures established by this section or through the application of the measures provided by the other sections of this chapter.

(b) After the freeze period, an electric utility located in a power region that is not certified under Section 39.152 shall continue to file annual reports under Sections 39.257, 39.258, and 39.259 as if the freeze period remained in effect, until the time the power region qualifies as certified under Section 39.152. In addition, the commission staff and the office shall continue to review the annual reports as provided by Section 39.261.

(c) After January 10, 2004, at a schedule and under procedures to be determined by the commission, each transmission and distribution utility, its affiliated retail electric provider, and its affiliated power generation company shall jointly file to finalize stranded costs under Subsections (h) and (i) and reconcile those costs with the estimated stranded costs used to develop the competition transition charge in the proceeding held under Section 39.201. Any resulting difference shall be applied to the nonbypassable delivery rates of the transmission and distribution utility, except that at the utility's option, any or all of the remaining stranded costs may be securitized under Subchapter G.

(d) The affiliated power generation company shall reconcile, and either credit or bill to the transmission and distribution utility, the net sum of:

(1) the former electric utility's final fuel balance determined under Section 39.202(c); and

(2) any difference between the price of power obtained through the capacity auctions under Sections 39.153 and 39.156 and the power cost projections that were employed for the same time period in the ECOM model to estimate stranded costs in the proceeding under Section 39.201.

(e) To the extent that the price to beat exceeded the market price of electricity, the affiliated retail electric provider shall reconcile and credit to the affiliated transmission and distribution utility any positive difference between the price to beat established under Section 39.202, reduced by the nonbypassable delivery charge established under Section 39.201, and the prevailing market price of electricity during the same time period. A reconciliation for the applicable customer class is not required under this subsection for an affiliated retail electric provider that satisfies the requirements of



Section 39.202(e)(1) or (2) before the expiration of two years from the introduction of customer choice. If a reconciliation is required, in no event shall the amount credited exceed an amount equal to the number of residential or small commercial customers served by the affiliated transmission and distribution utility that are buying electricity from the affiliated retail electric provider at the price to beat on the second anniversary of the beginning of competition, minus the number of new customers obtained outside the service area, multiplied by \$150.

(f) To the extent that any amount of regulatory assets included in a transition charge or competition transition charge exceeds the amount of regulatory assets approved in a rate order which became effective on or before September 1, 1999, the commission shall conduct a review during the true-up proceeding to determine whether such amounts were appropriately calculated and constituted reasonable and necessary costs pursuant to Subchapter B, Chapter 36. If the commission finds that the amount of regulatory assets specified in Section 39.302(5) is subject to modification, a credit or other rate adjustment shall be made to the transmission and distribution utility's nonbypassable delivery rates; provided, however, that no adjustment may be made to a transition charge established under Subchapter G.

(g) Based on the credits or bills received from its affiliates under Subsections (d), (e), and (f), the transmission and distribution utility shall make necessary adjustments to the nonbypassable delivery rates it charges to retail electric providers. If the commission determines that the nonbypassable delivery rates are not sufficient, the commission may extend the original collection period for the charge or, if necessary, increase the charge. Alternatively, if the commission determines that the nonbypassable delivery rates are larger than are needed to recover the transmission and distribution utility's costs, the commission shall correspondingly reduce:

- (1) the competition transition charge, to the extent it has not been securitized;
- (2) the depreciation expense that has been redirected under Section 39.256;
- (3) the transmission and distribution utility's rates; or
- (4) a combination of the elements in Subdivisions (1)-(3).

(h) Except as provided in Subsection (i), for the purpose of finalizing the stranded cost estimate used to establish the competition transition charge under Section 39.201, the affiliated power generation company shall quantify its stranded costs using one or more of the following methods:

(1) Sale of Assets. If, at any time after December 31, 1999, an electric utility or its affiliated power generation company has sold some or all of its generation assets, which sale shall include all generating assets associated with each generating plant that is sold, in a bona fide third-party

transaction under a competitive offering, the total net value realized from the sale establishes the market value of the generation assets sold. If not all assets are sold, the market value of the remaining generation assets shall be established by one or more of the other methods in this section.

(2) Stock Valuation Method. If, at any time after December 31, 1999, an electric utility or its affiliated power generation company has transferred some or all of its generation assets, including, at the election of the electric utility or power generation company, any fuel and fuel transportation contracts related to those assets, to one or more separate affiliated or nonaffiliated corporations, not less than 51 percent of the common stock of each corporation is spun off and sold to public investors through a national stock exchange, and the common stock has been traded for not less than one year, the resulting average daily closing price of the common stock over 30 consecutive trading days chosen by the commission out of the last 120 consecutive trading days before the filing required under Subsection (c) establishes the market value of the common stock equity in each transferee corporation. The book value of each transferee corporation's debt and preferred stock securities shall be added to the market value of its assets. The market value of each transferee corporation's assets shall be reduced by the corresponding net book value of the assets acquired by each transferee corporation from any entity other than the affiliated electric utility or power generation company. The resulting market value of the assets establishes the market value of the generation assets transferred by the electric utility or power generation company to each separate corporation. If not all assets are disposed of in this manner, the market value of the remaining assets shall be established by one or more of the other methods in this section.

(3) Partial Stock Valuation Method. If, at any time after December 31, 1999, an electric utility or its affiliated power generation company has transferred some or all of its generation assets, including, at the election of the electric utility or power generation company, any fuel and fuel transportation contracts related to those assets, to one or more separate affiliated or nonaffiliated corporations, at least 19 percent, but less than 51 percent, of the common stock of each corporation is spun off and sold to public investors through a national stock exchange, and the common stock has been traded for not less than one year, the resulting average daily closing price of the common stock over 30 consecutive trading days chosen by the commission out of the last 120 consecutive trading days before the filing required under Subsection (c) shall be presumed to establish the market value of the common stock equity in each transferee corporation. The commission may accept the market valuation to conclusively establish the value of the common stock equity in each transferee corporation or convene a valuation panel of three independent financial experts to determine whether the percentage of common

stock sold is fairly representative of the total common stock equity or whether a control premium exists for the retained interest. The valuation panel must consist of financial experts, chosen from proposals submitted in response to commission requests, from the top 10 nationally recognized investment banks with demonstrated experience in the United States electric industry as indicated by the dollar amount of public offerings of long-term debt and equity of United States investor-owned electric companies over the immediately preceding three years as ranked by the publications "Securities Data" or "Institutional Investor." If the panel determines that a control premium exists for the retained interest, the panel shall determine the amount of the control premium, and the commission shall adopt the determination but may not increase the market value by a control premium greater than 10 percent. The costs and expenses of the panel, as approved by the commission, shall be paid by each transferee corporation. The determination of the commission based on the finding of the panel conclusively establishes the value of the common stock of each transferee corporation. The book value of each transferee corporation's debt and preferred stock securities shall be added to the market value of its assets. The market value of each transferee corporation's assets shall be reduced by the corresponding net book value of the assets acquired by each transferee corporation from any entity other than the affiliated electric utility or power generation company. The resulting market value of the assets establishes the market value of the generation assets transferred by the electric utility or power generation company to each separate corporation.

(4) Exchange of Assets. If, at any time after December 31, 1999, an electric utility or its affiliated power generation company has transferred some or all of its generation assets, including any fuel and fuel transportation contracts related to those assets, in a bona fide third-party exchange transaction, the stranded costs related to the transferred assets shall be the difference between the book value and the market value of the transferred assets at the time of the exchange, taking into account any other consideration received or given. The market value of the transferred assets may be determined through an appraisal by a nationally recognized independent appraisal firm, if the market value is subject to a market valuation by means of an offer of sale in accordance with this subdivision. To obtain a market valuation by means of an offer of sale, the owner of the asset shall offer it for sale to other parties under procedures that provide broad public notice of the offer and a reasonable opportunity for other parties to bid on the asset. The owner of the asset may establish a reserve price for any offer based on the sum of the appraised value of the asset and the tax impact of selling the asset, as determined by the commission.

(i) Unless an electric utility or its affiliated power generation company combines all of its remaining generation assets into one or more transferee corporations as described in Subsections (h)(2) and (3), the electric utility shall quantify its stranded costs for nuclear assets using the ECOM method. The ECOM method is the estimation model prepared for and described by the commission's April 1998 Report to the Texas Senate Interim Committee on Electric Restructuring entitled "Potentially Strandable Investment (ECOM) Report: 1998 Update." The methodology used in the model must be the same as that used in the 1998 report to determine the "base case." At the time of the proceeding under this section, the ECOM model shall be rerun using updated company-specific inputs required by the model, updating the market price of electricity, and using updated natural gas price forecasts and the capacity cost based on the long-run marginal cost of the most economic new generation technology then available. Natural gas price projections used in the model must be market-based natural gas forward prices, where available. Growth rates in generating plant operations and maintenance costs and allocated administrative and general costs shall be benchmarked by comparing those costs to the best available information on cost trends for comparable generating plants. Capital additions shall be benchmarked using the limitation in Section 39.259(b).

(j) The commission shall issue a final order not later than the 150th day after the date of the filing under this section by the transmission and distribution utility, its affiliated retail electric provider, and its affiliated power generation company, and the resulting order shall be subject to judicial review under Chapter 2001, Government Code.

(k) Notwithstanding Section 39.252, to the extent that a customer's actual load has been lawfully served by a fully operational qualifying facility before September 1, 2001, or by an on-site power production facility with a rated capacity of 10 megawatts or less, any charge for recovery of stranded costs under this section or Subchapter G assessed on that customer after the facility becomes fully operational shall be included only in those tariffs or charges associated with the services actually provided by the transmission and distribution utility, if any, to the customer after the facility became fully operational and may not include any costs associated with the service provided to the customer by the electric utility or its affiliated transmission and distribution utility under their tariffs before the operation of that qualifying facility. To qualify under this subsection, a qualifying facility must have made substantially complete filings on or before December 31, 1999, for all necessary site-specific environmental permits under the rules of the Texas Natural Resource Conservation Commission in effect at the time of filing.

Sec. 39.263. STRANDED COST RECOVERY OF ENVIRONMENTAL CLEANUP COSTS.

(a) Subject to Subsection (c), capital costs incurred by an electric utility to improve air quality before January 1, 2002, are eligible for inclusion as net invested capital under Section 39.259, notwithstanding the limitations imposed under Sections 39.259(b) and (c).

(b) Subject to Subsection (c), capital costs incurred by an electric utility or an affiliated power generation company to improve air quality after January 1, 2002, and before May 1, 2003, are eligible for inclusion in the determination of invested capital in the true-up proceeding under Section 39.262.

(c) Reasonable costs incurred under Subsections (a) and (b) shall be included as invested capital and considered in an electric utility's stranded cost determination only to the extent that:

(1) the cost is applied to offset or reduce the emission of airborne contaminants from an electric generating facility, where:

(A) the reduction or offset is determined by the Texas Natural Resource Conservation Commission to be an essential component in achieving compliance with a national ambient air quality standard; or

(B) the reduction or offset is necessary in order for an unpermitted electric generating facility to obtain a permit in the manner provided by Section 39.264;

(2) the retrofit decision is determined to be the most cost-effective after consideration of alternative measures, including the retirement of the generating facility; and

(3) the amount and location of resulting emission reductions is consistent with the air quality goals and policies of the Texas Natural Resource Conservation Commission.

(d) If the retirement of a generating facility is the most cost-effective alternative, taking into account the cost of replacement generating capacity, the net book value, including retirement costs and offsetting salvage value, of the affected facility shall be included in the electric utility's stranded cost determination, notwithstanding Section 39.259(c).

Sec. 39.264. EMISSIONS REDUCTIONS OF "GRANDFATHERED FACILITIES." (a) In this section:

(1) "Conservation commission" means the Texas Natural Resource Conservation Commission.

(2) "Electric generating facility" means a facility that generates electric energy for compensation and is owned or operated by a person in this state, including a municipal corporation, electric cooperative, or river authority.

(b) This section applies only to an electric generating facility existing on January 1, 1999, that is not subject to the requirement to obtain a permit under Section 382.0518(g), Health and Safety Code.

(c) It is the intent of the legislature that, for the 12-month period beginning on May 1, 2003, and for each 12-month period after the end of that period, total annual emissions of nitrogen oxides from facilities subject to this section may not exceed levels equal to 50 percent of the total emissions of that pollutant during 1997, as reported to the conservation commission, and total annual emissions of sulphur dioxides from coal-fired facilities subject to this section may not exceed levels equal to 75 percent of the total emissions of that pollutant during 1997, as reported to the conservation commission. The limitations prescribed by this subsection may be met through an emissions allocation and allowance transfer system described by this section.

(d) A municipal corporation, electric cooperative, or river authority may exclude any electric generating facilities of 25 megawatts or less from the requirements prescribed by this section. Not later than January 1, 2000, a municipal corporation, electric cooperative, or river authority must inform the conservation commission of its intent to exclude those facilities.

(e) The owner or operator of an electric generating facility shall apply to the conservation commission for a permit for the emission of air contaminants on or before September 1, 2000. A permit issued by the conservation commission under this section shall require the facility to achieve emissions reductions or trading emissions allowances as provided by this section. If the facility uses coal as a fuel, the permit must also be conditioned on the facility's emissions meeting opacity limitations provided by conservation commission rules. Notwithstanding Section 382.0518(g), Health and Safety Code, a facility that does not obtain a permit as required by this subsection may not operate after May 1, 2003, unless the conservation commission finds good cause for an extension.

(f) The conservation commission shall develop rules for the permitting of electric generating facilities. The rules adopted under this subsection shall provide, by region, for the allocation of emissions allowances of sulphur dioxides and nitrogen oxides among electric generating facilities and for facilities to trade emissions allowances for those contaminants.

(g) The conservation commission by rule shall establish an East Texas Region, a West Texas Region, and an El Paso Region for allocation of air contaminants under the permitting program under Subsection (f). The East Texas Region must contain all counties traversed by or east of Interstate Highway 35 or Interstate Highway 37, including Bosque, Coryell, Hood, Parker, Somervell, and Wise counties. The West Texas Region includes all of the state not contained in the East Texas Region or the El Paso Region. The El Paso Region includes El Paso County.

(h) Not later than January 1, 2000, the conservation commission shall allocate to each electric generating facility in each region a number of annual emissions allowances, with each allowance equal to one ton of sulphur dioxides or of nitrogen oxides emitted in a year, that permit emissions of the contaminants from the facility in that year. The conservation commission must allocate to each facility a number of emissions allowances equal to an emissions rate measured in pounds per million British thermal units divided by 2,000 and multiplied by the facility's total heat input in terms of million British thermal units during 1997. For the East Texas Region, the emissions rate shall be 0.14 pounds per million British thermal units for nitrogen oxides and 1.38 pounds per million British thermal units for sulphur dioxides. For the West Texas and El Paso regions, the emissions rate shall be 0.195 pounds per million British thermal units for nitrogen oxides. Allowances for sulphur dioxides may only be allocated among coal-fired facilities.

(i) A person, municipal corporation, electric cooperative, or river authority that owns and operates an electric generating facility not covered by this section may elect to designate that facility to become subject to the requirements of this section and to receive emissions allowances for the purpose of complying with the emissions limitations prescribed by Subsection (c). The conservation commission shall adopt rules governing this election that:

(1) require an owner or operator of an electric generating facility to designate to the conservation commission in its permit application under Subsection (e) any facilities that will become subject to this section;

(2) require the conservation commission, notwithstanding the allocation mechanism provided by Subsection (h), to allocate additional allowances to facilities governed by this subsection in an amount equal to each facility's actual emissions in tons in 1997;

(3) provide that any unit designated under this subsection may not transfer or bank allowances conserved as a result of reduced utilization or shutdown, except that the allowances may be transferred or carried forward for use in subsequent years to the extent that the reduced utilization or shutdown results from the replacement of thermal energy from the unit designated under this subsection with thermal energy generated by any other unit; and

(4) provide that emissions reductions from electing facilities designated in this subsection may only be used to satisfy the emissions reductions for grandfathered facilities defined in Subsection (c) to the extent that reductions used to satisfy the limitations in Subsection (c) are beyond the requirements of any other state or federal standard, or both.

(j) The conservation commission by rule shall permit a facility to trade emissions allocations with other electric generating facilities only in the same region.

(k) The conservation commission by rule shall provide methods for the conservation commission to determine whether a facility complies with the permit issued under this section. The rules must provide for:

- (1) monitoring and reporting actual emissions of sulphur dioxides and nitrogen oxides from each facility;
- (2) provisions for saving unused allowances for use in later years; and
- (3) a system for tracking traded allowances.

(l) A facility may not trade an unused allowance for a contaminant for use as a credit for another contaminant.

(m) A person possessing market power shall not withhold emissions allowances from the market in a manner that is unreasonably discriminatory or tends to unreasonably restrict, impair, or reduce the level of competition.

(n) The conservation commission shall penalize a facility that emits an air contaminant that exceeds the facility's allowances for that contaminant by:

- (1) enforcing an administrative penalty, in an amount determined by conservation commission rules, for each ton of air contaminant emissions by which the facility exceeds its allocated emissions allowances; and
- (2) reducing the facility's emissions allowances for the next year by an amount of emissions equal to the excessive emissions in the year the facility emitted the excessive air contaminants.

(o) The conservation commission may penalize a facility that emits an air contaminant that exceeds the facility's allowances for that contaminant by:

- (1) ordering the facility to cease operations; or
- (2) taking other enforcement action provided by conservation commission rules.

(p) The conservation commission by rule shall provide for a facility in the El Paso Region to meet emissions allowances by using credits from emissions reductions achieved in Ciudad Juarez, United Mexican States.

(q) If the conservation commission or the United States Environmental Protection Agency determines that reductions in nitrogen oxides emissions in the El Paso Region otherwise required by this section would result in increased ambient ozone levels in El Paso County, facilities in the El Paso Region are exempt from the nitrogen oxides reduction requirements.



(r) An applicant for a permit under Subsection (e) shall publish notice of intent to obtain the permit in accordance with Section 382.056, Health and Safety Code. The conservation commission shall provide an opportunity for a public hearing and the submission of public comment and send notice of a decision on an application for a permit under Subsection (e) in the same manner as provided by Sections 382.0561 and 382.0562, Health and Safety Code. The conservation commission shall review and renew a permit issued under this section in accordance with Section 382.055, Health and Safety Code.

(s) This section does not limit the authority of the conservation commission to require further reductions of nitrogen oxides, sulphur dioxides, or any other pollutant from generating facilities subject to this section or Section 39.263.

Sec. 39.265. RIGHTS NOT AFFECTED. This chapter is not intended to alter any rights of utilities to recover stranded costs from wholesale customers.