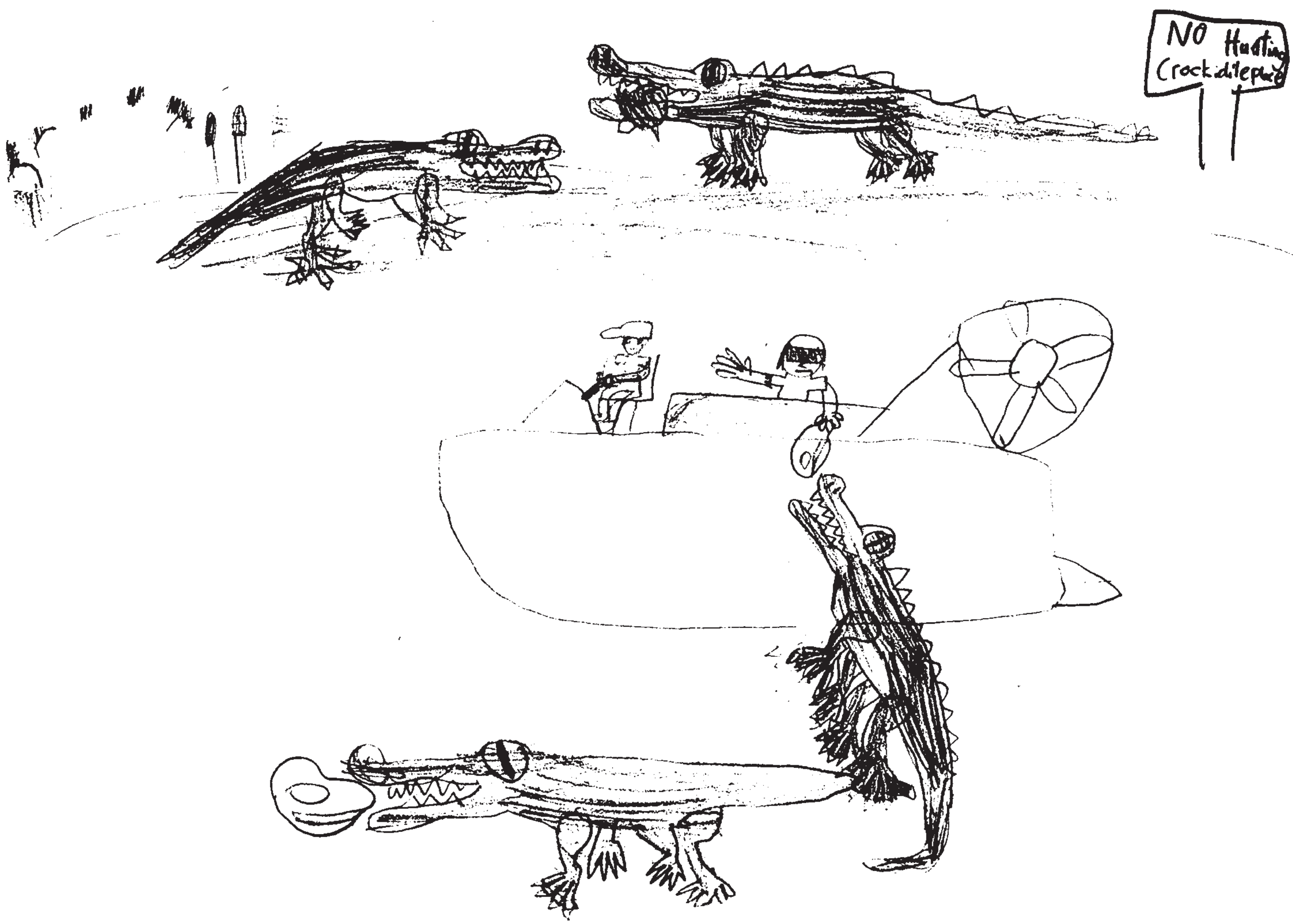
Texas Register

Volume 25 Number 1 January 7, 2000 Pages 1-248



This month's front cover artwork:

Artist: *Garrett Rhodes*

3rd Grade

Eustace Int. School

School children's artwork has decorated the blank filler pages of the *Texas Register* since 1987. Teachers throughout the state submit the drawings for students in grades K-12. The drawings dress up the otherwise gray pages of the *Texas Register* and introduce students to this obscure but important facet of state government.

We will display artwork on the cover of each *Texas Register.* The artwork featured on the front cover is chosen at random.

The artwork is published on what would otherwise be blank pages in the *Texas Register.* These blank pages are caused by the production process used to print the *Texas Register.* The artwork does not add additional pages to each issue and does not increase the cost of the *Texas Register.*

For more information about the student art project, please call (800) 226-7199.

Texas Register, **(ISSN 0362-4781)**, is published weekly, 52 times a year. Issues will be published by the Office of the Secretary of State, 1019 Brazos, Austin, Texas 78701. Subscription costs: printed, one year $150, six month $100. First Class mail subscriptions are available at a cost of $250 per year. Single copies of most issues for the current year are available at $10 per copy in printed format.

The ***Texas Register*** is published under the Government Code, Title 10, Chapter 2002. Periodicals Postage Paid at Austin, Texas.

POSTMASTER: Send address changes to the ***Texas Register***, P.O. Box 13824, Austin, TX 78711-3824.

OFFICE OF THE ATTORNEY GENERAL

Under provisions set out in the Texas Constitution, the Texas Government Code. Title 4, §402.042, and numerous statutes, the attorney general is authorized to write advisory opinions for state and local officials. These advisory opinions are requested by agencies or officials when they are confronted with unique or unusually difficult legal questions. The attorney general also determines, under authority of the Texas Open Records Act, whether information requested for release from governmental agencies may be held from public disclosure. Requests for opinions, opinions, and open records decisions are summarized for publication in the ***Texas Register***. The attorney general responds to many requests for opinions and open records decisions with letter opinions. A letter opinion has the same force and effect as a formal Attorney General Opinion, and represents the opinion of the attorney general unless and until it is modified or overruled by a subsequent letter opinion, a formal Attorney General Opinion, or a decision of a court of record. You may view copies of opinions at http://www.oag.state.tx.us. To request copies of opinions, please fax your request to (512) 462-0548 or call (512) 936-1730. To inquire about pending requests for opinions, phone (512) 463-2110.

Requests for Opinions

RQ-0160-JC. Requested by: The Honorable Ben W. "Bud" Childers, Fort Bend County Attorney, 301 Jackson, Suite 621 Richmond, Texas, 77469-3108 Re: What constitutes a "newspaper of general circulation" for the purpose of publishing legal notices, and related questions. (Request No. 0160-JC)

Briefs requested by January 23, 2000

RQ-0161-JC. Requested by: The Honorable Carole Keeton Rylander, Comptroller of Public Accounts, Lyndon B. Johnson Building, 111 East 17th Street, Austin, Texas, 78701 Re: Whether a county may discontinue its participation in the salary supplementation program established by section 51.702, Government Code, and related questions. (Request No. 0161-JC)

Briefs requested by January 22, 2000

RQ-0162-JC. Requested by: The Honorable Susan D. Reed, Bexar County Criminal District Attorney, 300 Dolorosa, Fifth Floor, San Antonio, Texas, 78205-3030 Re: Electronic transfer of tax revenues to county depository. (Request No. 0162-JC)

Briefs requested by January 23, 2000

RQ-0163-JC. Requested by: The Honorable Bill Ratliff, Chair, Finance Committee, Texas State Senate, P.O. Box 12068, 3S.5, Austin, Texas, 78711 Re: Regulation of the Oyster bed leasing program of the Texas Parks and Wildlife Department. (Request No. 0163-JC)

Briefs requested by January 27, 2000

RQ-0164-JC. Requested by: The Honorable Gary L. Walker, Chair, Land and Resource Management, Texas House of Representatives, P.O. Box 2910, E.2502, Austin, Texas, 78768-2910 Re: Whether a county may permit the installation of temporary water lines along its right of way. (Request No. 0164-JC)

Briefs requested by January 23, 2000

RQ-0165-JC. Requested by: The Honorable Chris D. Prentice, Hale County Attorney, 500 Broadway, Suite # 80 Plainview, Texas, 79072 Re: Whether a political subdivision that owns and operates a utility system or a sanitary landfill may contract with other governmental entities to collect unpaid service fees. (Request No. 0165-JC)

Briefs requested by January 23, 2000

TRD-9909078
Elizabeth Robinson
Assistant Attorney General
Office of the Attorney General
Filed: December 29, 1999

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Emergency Rules

An agency may adopt a new or amended section or repeal an existing section on an emergency basis if it determines that such action is necessary for the public health, safety, or welfare of this state. The section may become effective immediately upon filing with the ***Texas Register***, or on a stated date less than 20 days after filing and remaining in effect no more than 120 days. The emergency action is renewable once for no more than 60 additional days.

Symbology in amended emergency sections. New language added to an existing section is indicated by the text being underlined. [Brackets] and ~~strike-through~~ of text indicates deletion of existing material within a section.

TITLE 22. EXAMINING BOARDS

Part 9. TEXAS STATE BOARD OF MEDICAL EXAMINERS

Chapter 163. LICENSURE

22 TAC §163.1, §163.5

The Texas State Board of Medical Examiners adopts on an emergency basis amendments to §163.1 and §163.5, concerning licensure examinations and official translations of documents.

The rules will protect the public by licensing only those physicians who pass licensure examinations that meet national standards. The rules will also clarify the information required by the board relating to certified translation of documents.

These sections are being adopted on an emergency basis due to the legislature mandating a January 7, 2000, deadline for these amendments to be effective.

The amendments are adopted on an emergency basis under the authority of the Occupations Code, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §155.051 is affected by the adopted amendments.

§163.1. Definitions.

The following words and terms, when used in this chapter, shall have the following meanings, unless the contents clearly indicate otherwise.

(1)-(6) (No change.)

(7) Examinations accepted by the board for licensure.

(A)-(F) (No change.)

(G) State board examination, before January 1, 1977, (with the exception of Florida, Virgin Islands, Guam, Tennessee Osteopathic Board or Puerto Rico after June 30, 1963); or

(H)-(J) (No change.)

(8)-(15) (No change.)

§163.5. Licensure Documentation.

(a) (No change.)

(b) Documentation required of all applicants for licensure.

(1)-(12) (No change.)

(13) Graduate Training Verification. Each applicant must submit a certificate showing successful completion of required training. The certificate must show the beginning and ending dates of the program and state that the program was successfully completed. An applicant must [~~may~~] have the current Program Director of the program in which the applicant trained submit a letter, addressed to this board, submitted directly to this board stating the beginning and ending dates of the program and attesting to successful completion.

(14)-(18) (No change.)

(c) (No change.)

(d) Applicants may be required to submit other documentation, which may include the following.

(1) Translations. Any document that is in a language other than the English language will need to have a certified translation prepared and a copy of the translation will have to be submitted along with the translated document.

(A) An official translation from the medical school (or appropriate agency) attached to the foreign language transcript or other document is acceptable.

(B) If a foreign document is received without a translation, the board will send the applicant a copy of the document to be translated and returned to the board.

(C) Documents must be translated by a translation agency who is a member of the American Translations Association or a United States college or university official.

(D) The translation must be on the translator's letterhead, and the translator must verify that it is a "true word for word translation" to the best of his/her knowledge, and that he/she is fluent in the language translated, and is qualified to translate the document.

(E) The translation must be signed in the presence of a notary public and then notarized. The translator's name must be printed below his/her signature. The notary public must use this phrase: "Subscribed and Sworn to this ___ day of _________, 20___." The notary must then sign and date the translation, and affix his/her Notary Seal to the document.

(2)-(7) (No change.)

(e) (No change.)

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9909003
Bruce A. Levy, M.D., J.D.
Executive Director

Texas State Board of Medical Examiners
Effective date: December 22, 1999
Expiration date: April 20, 2000
For further information, please call: (512) 305-7016

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Chapter 165. MEDICAL RECORDS

22 TAC §165.2

The Texas State Board of Medical Examiners adopts on an emergency basis an amendment to §165.2, concerning medical records.

The amendment will clarify charges for affidavits that may accompany copies of medical records certifying that the copy is a true and correct copy of the original.

The section is being adopted on an emergency basis due to the legislature mandating a January 7, 2000, deadline for the amendment to be effective.

The amendment is adopted on an emergency basis under the authority of the Occupations Code, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §159.006 is affected by the adopted amendment.

§165.2. Medical Record Release and Charges.

(a)-(d) (No change.)

(e) The physician responding to a request for such information shall be entitled to receive a reasonable fee for providing the requested information. A reasonable fee shall be a charge of no more than $25 for the first 20 pages and $.15 per page for every copy thereafter. In addition, a reasonable fee may include actual costs for mailing, shipping, or delivery. <u>If an affidavit is requested, certifying that the information is a true and correct copy of the records, a reasonable fee of up to $10 may be charged for executing the affidavit.</u>

(f)-(i) (No change.)

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9909004
Bruce A. Levy, M.D., J.D.
Executive Director
Texas State Board of Medical Examiners
Effective date: December 22, 1999
Expiration date: April 20, 2000
For further information, please call: (512) 305-7016

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Chapter 171. INSTITUTIONAL PERMITS

22 TAC §171.1

The Texas State Board of Medical Examiners adopts on an emergency basis an amendment to §171.1, concerning permits issued to physicians in postgraduate training programs.

The amendment will clarify the provisions of the Medical Practice Act under which physicians holding training permits may be disciplined.

The section is being adopted on an emergency basis due to the legislature mandating a January 7, 2000, deadline for the amendment to be effective.

The amendment is adopted on an emergency basis under the authority of the Occupations Code, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §155.105 is affected by the adopted amendment.

§171.1. Construction.

(a)-(g) (No change.)

<u>(h) A violation of §3.08 or any other provision of the Medical Practice Act is grounds for denial, non-renewal or cancellation of a permit.</u>

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9909005
Bruce A. Levy, M.D., J.D.
Executive Director
Texas State Board of Medical Examiners
Effective date: December 22, 1999
Expiration date: April 20, 2000
For further information, please call: (512) 305-7016

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Chapter 173. PHYSICIAN PROFILES

22 TAC §§173.1-173.7

The Texas State Board of Medical Examiners adopts on an emergency basis new §§173.1-173.7, concerning information to be collected by the board as mandated by House Bill 110, 76th Legislature.

The rules will outline the information to be collected and made available to the public. This will enable the public to access information via the Internet or in paper format that will be helpful in making informed decisions regarding the choice of a physician.

These sections are being adopted on an emergency basis due to the legislature mandating a January 7, 2000, deadline for the new sections to be effective.

The new sections are adopted on an emergency basis under the authority of the Occupations Code, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §160.002 is affected by the adopted new sections.

<u>*§173.1. Profile Contents.*</u>

<u>(a) The Texas State Board of Medical Examiners (the "board") shall develop and make available to the public a comprehensive profile of each licensed physician electronically via the Internet or in paper format upon request.</u>

<u>(b) The profile of each licensed physician shall contain the following information listed in paragraphs (1)-(28) of this subsection:</u>

(1) full name;

(2) date and place of birth;

(3) gender;

(4) ethnic origin;

(5) name of each medical school attended and the dates of:

(A) graduation; or

(B) Fifth Pathway designation and completion of the Fifth Pathway Program;

(6) a description of all graduate medical education in the United States or Canada, including:

(A) beginning and ending dates;

(B) program name;

(C) city and state of program;

(D) type of training (internship, residency or fellowship); and,

(E) specialty of program;

(7) any specialty certification held by the physician and issued by a board that is a member of the American Board of Medical Specialties or the Bureau of Osteopathic Specialists;

(8) primary and secondary specialties practiced, as designated by the physician;

(9) the number of years the physician has actively practiced medicine in:

(A) the United States or Canada; and

(B) Texas;

(10) the original date of issuance of the physician's Texas medical license;

(11) the expiration date of the physician's annual registration permit;

(12) the physician's current registration, disciplinary and licensure statuses and dates of such statuses;

(13) the physician's Continuing Medical Education status;

(14) the expiration date of the physician's permit to conduct outpatient anesthesia services, if applicable;

(15) the method of licensure of the physician's original Texas medical license, and, if by reciprocal endorsement, the state and/or province of reciprocal endorsement;

(16) the name and city of each hospital in Texas in which the physician has privileges;

(17) the physician's primary practice location (street address, city, state and zip code);

(18) the physician's mailing address (street address or post office box, city, state and zip code);

(19) the type of language translating services, including translating services for a person with impairment of hearing, that the physician provides at the physician's primary practice location;

(20) whether the physician participates in the Medicaid program;

(21) whether the physician's patient service areas are accessible to disabled persons, as defined by federal law;

(22) a description of any conviction for an offense constituting a felony, a Class A or Class B misdemeanor, or a Class C misdemeanor involving moral turpitude during the ten-year period preceding the date of the profile;

(23) a description of any charges reported to the board during the ten-year period preceding the date of the profile to which the physician has pleaded no contest, for which the physician is the subject of deferred adjudication or pretrial diversion, or in which sufficient facts of guilt were found and the matter was continued by a court of competent jurisdiction;

(24) a description of any disciplinary action against the physician by the board;

(25) a description of any disciplinary action against the physician by a medical licensing board of another state during the ten-year period preceding the date of the profile;

(26) a description of the final resolution taken by the board on medical malpractice claims or complaints required to be opened by the board under §5.05(f) of the Medical Practice Act (Article 4495b, Vernon's Texas Civil Statutes);

(27) a description of any formal complaint issued by the Board's staff against the physician and initiated and filed with the State Office of Administrative Hearings under §4.03 of the Medical Practice Act (Article 4495b, Vernon's Texas Civil Statutes) and the status of the complaint; and,

(28) a description of a maximum of 5 awards, honors, publications or academic appointments submitted by the physician, each no longer than 120 characters.

§173.2. Profile Update and Correction Form.

(a) The board shall develop a Profile Update and Correction Form (the "Form") which allows for corrections and/or updates to the profile information to be made by the physician. The physician must submit all changes to profile information upon this Form, or indicate on the Form that no changes are necessary. The Form shall contain the date the information will be made available to the public and will allow the physician to request a copy of the physician's profile. Upon such request, and when the profile information has been updated, the board shall provide a copy to the physician. The Form will be made available in hard copy and on the Internet.

(b) Compliance with the request for information from the board is mandatory. Failure to return the completed Form to the board shall be considered non-compliance. Non-compliance shall result in nonrenewal of the physician's license until such time as the physician provides the requested information.

(c) Submission of false or misleading information by the physician shall be considered grounds for disciplinary action.

(d) All data contained in the profile shall indicate the source of the data and the last update date.

§173.3. Initial Collection of Profile Data and Physician-Initiated Updates During the Renewal Process.

(a) The board shall send a copy of the Form to the physician with the physician's annual renewal form.

(b) The physician shall comply with the request for information by returning the Form to the board prior to the expiration date of the physician's annual registration permit.

§173.4. Updates to the Physician's Profile Due to Board Action.

When the board takes disciplinary action against a physician, such action shall be noted on the physician's profile and shall be made available to the public.

§173.5. Updates to the Physician's Profile Due to Information Received by a Third Party.

When the board is notified by a third party of a change in profile information for a physician, the board shall send a copy of the Form to the physician with the changes noted. The physician shall have one month in which to correct factual errors or dispute the information.

§173.6. Physician-Initiated Updates Outside of the Renewal Process.

If the profile needs correction outside of the regular renewal process, the physician shall request that the Form be mailed to the physician for corrections. The physician must then use the Form to submit corrections to the profile information to the board.

§173.7. Corrections and the Dispute Process.

(a) If the physician wishes to make corrections or dispute the proposed profile information, the procedures in this section shall apply.

(b) If the board receives the Form from the physician without corrections to the profile information, the profile shall be made available to the public as is.

(c) If the board receives the Form from the physician and the physician has indicated corrections to the information on the Form, the board shall review the proposed corrections.

(d) If the board determines that the physician's corrections are satisfactory, the board shall update the profile information and make the profile available to the public.

(e) If the board determines that the physician's corrections are unsatisfactory, the board shall so notify the physician, along with a presentation of the information in a format satisfactory to the board, and instructions of the process that the physician must follow to dispute the information.

(f) If the physician wishes to dispute the profile information which is in the format satisfactory to the board, the physician must submit a formal letter of dispute to the board within two weeks of the date of the notification in subsection (e) of this section. The physician must then submit proof of factual error to the board within one month of the date of the notification in subsection (e) of this section.

(g) Upon receipt of the formal letter of dispute from the physician, a notation that the information under dispute is "Not available" shall be attached to the appropriate category of the physician's profile and such notation shall be made available to the public on the profile.

(h) After review of the proof provided by the physician during the dispute process as described in subsection (f) of this section, the board shall make a determination as to the profile information to be provided to the public.

(i) Upon determination by the board of the dispute, the board shall notify the physician of the determination, shall update the physician's profile with the information, shall remove the "Not available" notation and shall make the profile available to the public.

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9909006
Bruce A. Levy, M.D., J.D.
Executive Director
Texas State Board of Medical Examiners
Effective date: December 22, 1999
Expiration date: April 20, 2000
For further information, please call: (512) 305-7016

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Chapter 175. FEES, PENALTIES AND APPLICATIONS

22 TAC §175.1, §175.5

The Texas State Board of Medical Examiners adopts on an emergency basis amendments to §175.1 and §175.5, concerning the fee and application for office-based anesthesia registration.

The fees collected will implement the program of registering physicians using office-based anesthesia, as mandated by Senate Bill 1340, 76th Legislature.

These sections are being adopted on an emergency basis due to the legislature mandating a January 7, 2000, deadline for these amendments to be effective.

The amendments are adopted on an emergency basis under the authority of the Occupations Code, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §153.051 is affected by the adopted amendments.

§175.1. Fees.

The board shall charge the following fees.

(1)-(6) (No change.)

(7) Miscellaneous Fees:

(A)-(B) (No change.)

(C) reinstatement after cancellation for cause - $350; [~~.~~]

(D) office-based anesthesia registration - $300.

§175.5. Applications.

(a) All information required on applications used by this board will conform to the Medical Practice Act and rules promulgated by this board. The board hereby adopts by reference the following forms:

(1)-(6) (No change.)

(7) Miscellaneous Applications:

(A)-(B) (No change.)

(C) physician designation of prescriptive delegation; [~~.~~]

(D) application for office-based anesthesia registration.

(b) (No change.)

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9909007
Bruce A. Levy, M.D., J.D.
Executive Director

Texas State Board of Medical Examiners
Effective date: December 22, 1999
Expiration date: April 20, 2000
For further information, please call: (512) 305-7016

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Chapter 183. ACUPUNCTURE

22 TAC §183.4

The Texas State Board of Medical Examiners adopts on an emergency basis an amendment to §183.4, concerning the computer based score for passage of the Test of English as a Foreign Language.

The amendment will clarify the minimum score required for passage of the computer based Test of English as a Foreign Language.

The section is being adopted on an emergency basis due to the legislature mandating a January 7, 2000, deadline for the amendment to be effective.

The amendment is adopted on an emergency basis under the authority of the Occupations Code, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §§205.101, 205.202, and 205.203 is affected by the adopted amendment.

§183.4. Licensure.

(a) Qualifications. An applicant must present satisfactory proof to the acupuncture board that the applicant:

(1)-(6) (No change.)

(7) is able to communicate in English as demonstrated by one of the following:

(A) (No change.)

(B) passage of the TOEFL (Test of English as a Foreign Language) with a score of 550 or higher on the paper based test or with a score of 213 or higher on the computer based test; or

(C)-(F) (No change.)

(b)-(g) (No change.)

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9909008
Bruce A. Levy, M.D., J.D.
Executive Director
Texas State Board of Medical Examiners
Effective date: December 22, 1999
Expiration date: April 20, 2000
For further information, please call: (512) 305-7016

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Chapter 192. OFFICE-BASED ANESTHESIA

22 TAC §§192.1-192.6

The Texas State Board of Medical Examiners adopts on an emergency basis new Chapter 192, §§192.1-192.6, concerning responsibilities of physicians providing, or overseeing by proper delegation, anesthesia services in outpatient settings and to provide the minimum acceptable standards for the provision of anesthesia services in outpatient settings, as mandated by Senate Bill 1340, 76th Legislature.

These rules will protect the public by assuring that physicians adhere to acceptable standards in the provision of anesthesia services in office-based settings.

These sections are being adopted on an emergency basis due to the legislature mandating a January 7, 2000, deadline for the new sections to be effective.

The new sections are adopted on an emergency basis under the authority of the Occupations Code, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §153.001 is affected by the adopted new sections.

§192.1. Definitions.

The following words and terms, when used in this chapter, shall have the following meanings, unless the contents indicate otherwise.

(1) Anesthesiologist's assistant - A graduate of an approved anesthesiologist's assistant training program.

(2) Anesthesiology resident - A physician who is presently in an approved Texas anesthesiology residency program who is either licensed as a physician in Texas or holds a postgraduate resident permit issued by the Texas State Board of Medical Examiners.

(3) Certified registered nurse anesthetist - A person licensed by the Board of Nurse Examiners for the State of Texas (BNE) as a registered professional nurse, authorized by the BNE as an advanced practice nurse in the role of nurse anesthetist, and certified by a national certifying body recognized by the BNE.

(4) Monitored anesthesia care - Situations where a patient undergoing a diagnostic or therapeutic procedure receives doses of medication that create a risk of loss of normal protective reflexes or loss of consciousness and the patient remains able to protect the airway for the majority of the procedure. If, for an extended period of time, the patient is rendered unconscious and/or loses normal protective reflexes, then anesthesia care shall be considered a general anesthetic.

(5) Outpatient setting - Any facility, clinic, center, office, or other setting that is not a part of a licensed hospital or a licensed ambulatory surgical center with the exception of all of the following listed in subparagraphs (A)-(D) of this paragraph:

(A) a clinic located on land recognized as tribal land by the federal government and maintained or operated by a federally recognized Indian tribe or tribal organization as listed by the United States secretary of the interior under 25 U.S.C. §479-1 or as listed under a successor federal statute or regulation;

(B) a facility maintained or operated by a state or governmental entity;

(C) a clinic directly maintained or operated by the United States or by any of its departments, officers, or agencies; and

(D) an outpatient setting accredited by either the Joint Commission on Accreditation of Healthcare Organizations relating to ambulatory surgical centers, the American Association for the

Accreditation of Ambulatory Surgery Facilities, or the Accreditation Association for Ambulatory Health Care.

(6) Board - The Texas State Board of Medical Examiners.

(7) Physician - A person licensed by the Texas State Board of Medical Examiners as a medical doctor or doctor of osteopathic medicine who diagnoses, treats, or offers to treat any disease or disorder, mental or physical, or any physical deformity or injury by any system or method or effects cures thereof and charges therefor, directly or indirectly, money or other compensation. "Physician" and "surgeon" shall be construed as synonymous.

§192.2. Provision of Anesthesia in Outpatient Settings.

(a) The purpose of these rules is to identify the roles and responsibilities of physicians providing, or overseeing by proper delegation, anesthesia services in outpatient settings and to provide the minimum acceptable standards for the provision of anesthesia services in outpatient settings.

(b) Beginning September 1, 2000, physicians shall comply with the rules promulgated under this title in order to be authorized to provide general anesthesia, regional anesthesia, or monitored anesthesia care in outpatient settings.

(c) The rules promulgated under this title do not apply to physicians who practice in the following settings listed in paragraphs (1)-(8) of this subsection:

(1) an outpatient setting in which only local anesthesia, peripheral nerve blocks, or both are used;

(2) an outpatient setting in which only anxiolytics and analgesics are used and only in doses that do not have the significant probability of placing the patient at risk for loss of the patient's life-preserving protective reflexes;

(3) a licensed hospital, including an outpatient facility of the hospital that is separately located apart from the hospital;

(4) a licensed ambulatory surgical center;

(5) a clinic located on land recognized as tribal land by the federal government and maintained or operated by a federally recognized Indian tribe or tribal organization as listed by the United States secretary of the interior under 25 U.S.C. §479-1 or as listed under a successor federal statute or regulation;

(6) a facility maintained or operated by a state or governmental entity;

(7) a clinic directly maintained or operated by the United States or by any of its departments, officers, or agencies; and

(8) an outpatient setting accredited by:

(A) the Joint Commission on Accreditation of Healthcare Organizations relating to ambulatory surgical centers;

(B) the American Association for the Accreditation of Ambulatory Surgery Facilities; or

(C) the Accreditation Association for Ambulatory Health Care.

(d) Anesthesiologists in outpatient settings shall follow current, applicable standards and guidelines as put forth by the American Society of Anesthesiologists (ASA) including, but not limited to, the following listed in paragraphs (1)-(8) of this subsection:

(1) Basic Standards for Preanesthesia Care;

(2) Standards for Basic Anesthetic Monitoring;

(3) Standards for Postanesthesia Care;

(4) Position on Monitored Anesthesia Care;

(5) The ASA Physical Status Classification System;

(6) Guidelines for Nonoperating Room Anesthetizing Locations;

(7) Guidelines for Ambulatory Anesthesia and Surgery; and

(8) Guidelines for Office-Based Anesthesia.

(e) A physician delegating the provision of anesthesia or anesthesia-related services to a certified registered nurse anesthetist shall be in compliance with ASA standards when the certified registered nurse anesthetist provides a service specified in the ASA standards to be provided by an anesthesiolgist.

(f) In an outpatient setting, where a physician has delegated to a certified registered nurse anesthetist the ordering of drugs and devices necessary for the nurse anesthetist to administer an anesthetic or an anesthesia-related service ordered by a physician, a certified registered nurse anesthetist may select, obtain and administer drugs, including determination of appropriate dosages, techniques and medical devices for their administration and in maintaining the patient in sound physiologic status. This order need not be drug-specific, dosage specific, or administration-technique specific. Pursuant to a physician's order for anesthesia or an anesthesia-related service, the certified registered nurse anesthetist may order anesthesia-related medications during perianesthesia periods in the preparation for or recovery from anesthesia. In providing anesthesia or an anesthesia-related service, the certified registered nurse anesthetist shall select, order, obtain and administer drugs which fall within categories of drugs generally utilized for anesthesia or anesthesia-related services and provide the concomitant care required to maintain the patient in sound physiologic status during those experiences.

(g) The anesthesiologist or physician providing anesthesia or anesthesia-related services in an outpatient setting shall perform a pre-anesthetic assessment, counsel the patient, and prepare the patient for anesthesia per current ASA standards. If the physician has delegated the provision of anesthesia or anesthesia-related services to a CRNA, the CRNA may perform these services. Informed consent for the planned anesthetic intervention shall be obtained from the patient/legal guardian and maintained as part of the medical record. The consent must include explanation of the technique, expected results, and potential risks/complications. Appropriate pre-anesthesia diagnostic testing and consults shall be obtained per indications and assessment findings. Pre-anesthetic diagnostic testing and specialist consultation should be obtained as indicated by the pre-anesthetic evaluation by the anesthesiologist or suggested by the nurse anesthetist's pre-anesthetic assessment as reviewed by the surgeon. If responsibility for a patient's care is to be shared with other physicians or non-physician anesthesia providers, this arrangement should be explained to the patient.

(h) Physiologic monitoring of the patient shall be determined by the type of anesthesia and individual patient needs. Minimum monitoring shall include continuous monitoring of ventilation, oxygenation, and cardiovascular status. Monitors shall include, but not be limited to, pulse oximetry and EKG continuously and non-invasive blood pressure to be measured at least every five minutes. If general anesthesia is utilized, then an O2 analyzer and end-tidal CO2 analyzer must also be used. A means to measure temperature shall be readily available and utilized for continuous monitoring when indicated per current ASA standards. An audible signal alarm device capable of detecting disconnection of any component of the breathing system shall be utilized. The patient shall be monitored continuously throughout the duration of the procedure. Postoperatively, the patient shall be evaluated by continuous monitoring and clinical observation until stable by a licensed health care provider. Monitoring and observations shall be documented per current ASA standards. In the event of an electrical outage which disrupts the capability to continuously monitor all specified patient parameters, at a minimum, heart rate and breath sounds will be monitored on a continuous basis using a precordial stethoscope or similar device, and blood pressure measurements will be reestablished using a non-electrical blood pressure measuring device until electricity is restored. There should be in each location, sufficient electrical outlets to satisfy anesthesia machine and monitoring equipment requirements, including clearly labeled outlets connected to an emergency power supply. A two-way communication source not dependent on electrical current shall be available. Sites shall also have a secondary power source as appropriate for equipment in use in case of power failure.

(i) All anesthesia-related equipment and monitors shall be maintained to current operating room standards. All devices shall have regular service/maintenance checks at least annually or per manufacturer recommendations. Service/maintenance checks shall be performed by appropriately qualified biomedical personnel. Prior to the administration of anesthesia, all equipment/monitors shall be checked using the current FDA recommendations as a guideline. Records of equipment checks shall be maintained in a separate, dedicated log which must be made available upon request. Documentation of any criteria deemed to be substandard shall include a clear description of the problem and the intervention. If equipment is utilized despite the problem, documentation must clearly indicate that patient safety is not in jeopardy. All documentation relating to equipment shall be maintained for seven years or for a period of time as determined by the board.

(j) Each location must have emergency supplies immediately available. Supplies should include emergency drugs and equipment appropriate for the purpose of cardiopulmonary resuscitation. This must include a defibrillator, difficult airway equipment, and drugs and equipment necessary for the treatment of malignant hyperthermia if "triggering agents" associated with malignant hyperthermia are used or if the patient is at risk for malignant hyperthermia. Equipment shall be appropriately sized for the patient population being served. Resources for determining appropriate drug dosages shall be readily available. The emergency supplies shall be maintained and inspected by qualified personnel for presence and function of all appropriate equipment and drugs at intervals established by protocol to ensure that equipment is functional and present, drugs are not expired, and office personnel are familiar with equipment and supplies. Records of emergency supply checks shall be maintained in a separate, dedicated log and made available upon request. Records of emergency supply checks shall be maintained for seven years or for a period of time as determined by the board.

(k) The operating surgeon shall verify that the appropriate policies or procedures are in place. Policies, procedure, or protocols shall be evaluated and reviewed at least annually. Agreements with local emergency medical service (EMS) shall be in place for purposes of transfer of patients to the hospital in case of an emergency. EMS agreements shall be evaluated and re-signed at least annually. Policies, procedure, and transfer agreements shall be kept on file in the setting where procedures are performed and shall be made available upon request. Policies or procedures must include, but are not limited to the following listed in paragraphs (1)-(2) of this subsection:

(1) Management of outpatient anesthesia. At a minimum, these must address:

(A) patient selection criteria;

(B) patients/providers with latex allergy;

(C) pediatric drug dosage calculations, where applicable;

(D) ACLS (advanced cardiac life support) or PALS (pediatric advanced life support) algorithms;

(E) infection control;

(F) documentation and tracking use of pharmaceuticals, including controlled substances, expired drugs and wasting of drugs; and

(G) discharge criteria.

(2) Management of emergencies. At a minimum, these must include, but not be limited to:

(A) cardiopulmonary emergencies;

(B) fire;

(C) bomb threat;

(D) chemical spill; and

(E) natural disasters.

(l) Operating surgeons or anesthesiologists shall maintain current competency in ACLS, PALS, or a course approved by the board. In all settings under these rules, at a minimum, at least two persons, including the surgeon or anesthesiologist, shall maintain current competency in basic life support.

(m) Physicians or surgeons must notify the board in writing within 15 days if a procedure performed in any of the settings under these rules resulted in a patient's death intraoperatively or within the immediate postoperative period. Immediate postoperative period is defined as 72 hours.

§192.3. Compliance with Office-Based Anesthesia Rules.

(a) On or after August 31, 2000, a physician who practices medicine in this state and who administers anesthesia or performs a surgical procedure for which anesthesia services are provided in an outpatient setting shall comply with the rules adopted under this title.

(b) The board may require a physician to submit and comply with a corrective action plan to remedy or address any current or potential deficiencies with the physician's provision of anesthesia in a outpatient setting in accordance with the Medical Practice Act, Article 4495b, Texas Revised Civil Statutes, or rules of the board.

(c) Any physician who violates these rules shall be subject to disciplinary action and/or termination of the registration issued by the board as authorized by the Medical Practice Act, Article 4495b, Texas Revised Civil Statutes.

§192.4. Annual Registration.

(a) Beginning September 1, 2000, the board shall require each physician who administers anesthesia or performs a surgical procedure for which anesthesia services are provided in an outpatient setting to annually register with the board on a form prescribed by the board and to pay a fee to the board in an amount established by the board.

(b) The board shall coordinate the registration required under this section with the registration required under the Medical Practice Act, Article 4495b, Texas Revised Civil Statutes, §3.01, so that the times of registration, payment, notice, and imposition of penalties for late payment are similar and provide a minimum of administrative burden to the board and to physicians.

§192.5. Inspections.

(a) The board may conduct inspections to enforce these rules, including inspections of an office site and of documents of a physician's practice that relate to the provision of anesthesia in an outpatient setting. The board may contract with another state agency or qualified person to conduct these inspections.

(b) Unless it would jeopardize an ongoing investigation, the board shall provide at least five business days' notice before conducting an on-site inspection under this section.

(c) This section does not require the board to make an on-site inspection of a physician's office.

§192.6. Requests for Inspection and Advisory Opinion.

(a) The board may consider a request by a physician for an on-site inspection. The board may, in its discretion and on payment of a fee in an amount established by the board, conduct the inspection and issue an advisory opinion.

(b) An advisory opinion issued by the board under this section is no binding on the board, and the board, except as provided by subsection (c) of this section, may take any action under the Medical Practice Act, Article 4495b, Texas Revised Civil Statutes, in relation to the situation addressed by the advisory opinion that the board considers appropriate.

(c) A physician who requests and relies on an advisory opinion of the board may use the opinion as mitigating evidence in an action or proceeding to impose an administrative or civil penalty under the Medical Practice Act, Article 4495b, Texas Revised Civil Statutes. The board or court, as appropriate, shall take proof of reliance on an advisory opinion into consideration and mitigate the imposition of administrative or civil penalties accordingly.

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9909009
Bruce A. Levy, M.D., J.D.
Executive Director
Texas State Board of Medical Examiners
Effective date: December 22, 1999
Expiration date: April 20, 2000
For further information, please call: (512) 305-7016

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Chapter 193. STANDING DELEGATION ORDERS

22 TAC §193.9

The Texas State Board of Medical Examiners adopts on an emergency basis new §193.9, concerning pronouncement of death.

The new section will enable physicians to make a pronouncement of death based on facts given to them by licensed vocational nurses through electronic communication.

The new section is being adopted on an emergency basis due to the legislature mandating a January 7, 2000, deadline for the new section to be effective.

The new section is adopted on an emergency basis under the authority of the Occupations Code, §153.001, which provides the Texas State Board of Medical Examiners to adopt rules and bylaws as necessary to: govern its own proceedings; perform its duties; regulate the practice of medicine in this state; and enforce this subtitle.

The Occupations Code, §157.001 is affected by the adopted new section.

§193.9. Pronouncement of Death.

(a) Purpose. These rules are promulgated under the authority of the Medical Practice Act, §3.06(d), to allow physicians to receive information from Texas licensed vocational nurses through electronic communication for the purpose of making a pronouncement of death. Electronic communication includes, but is not limited to telephone, facsimile transmission, or electronic mail.

(b) Do not resuscitate order. A do not resuscitate (DNR) order must be kept in the patient's file.

(c) Required information. In order to make a pronouncement of death through electronic communication, a physician must receive, at a minimum, the following information listed in paragraphs (1)-(5) of this subsection regarding the condition of the patient:

(1) absence of palpable pulse for a minimum of 60 seconds;

(2) absence of discernible blood pressure for a minimum of 60 seconds;

(3) absence of evidence of respiration for a minimum of 60 seconds;

(4) absence of evidence of heartbeat for a minimum of 60 seconds; and

(5) other information as the physician may require.

(d) Follow-up by physician. If a physician makes a pronouncement of death based on information received pursuant to subsection (c) of this section, the physician must personally view the body of the deceased and sign the death certificate within eight hours of the pronouncement.

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9909010
Bruce A. Levy, M.D., J.D.
Executive Director
Texas State Board of Medical Examiners
Effective date: December 22, 1999
Expiration date: April 20, 2000
For further information, please call: (512) 305-7016

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TITLE 34. PUBLIC FINANCE

Part 3. TEACHER RETIREMENT SYSTEM OF TEXAS

Chapter 41. INSURANCE PROGRAMS [~~HEALTH CARE BENEFITS~~]

Subchapter B. LONG-TERM CARE, DISABILITY AND LIFE INSURANCE

34 TAC §41.15

The Teacher Retirement System of Texas (TRS) adopts on an emergency basis a new §41.15 concerning the requirements to bid on insurance for school district employees and retirees. The new rule is to be adopted on an emergency basis pursuant to §2001.034 of the Texas Government Code, which allows a state agency to adopt an emergency rule if a requirement of state or federal law requires adoption of the rule on less than 30 days notice. The new rule will implement Insurance Code article 3.50-4A, which was passed by the 76th Legislature, 1999 in Senate Bill 1128 and became effective September 1, 1999. In addition, an amendment to the title of Chapter 41 is adopted on an emergency basis which will more accurately reflect the subject matter of the chapter. New titles for subchapters A and B are also being adopted on an emergency basis. The new section is being simultaneously proposed for permanent adoption in this issue.

In accordance with the new law, the rule sets forth the requirements for the selection of contractors for new insurance plans established by Insurance Code article 3.50-4A, including long-term care insurance, optional permanent life insurance, and short-term and long-term disability insurance. The selection requirements include minimum premium income requirements and minimum capital and surplus requirements. These criteria are necessary to ensure financial stability and integrity of the new programs and are consistent with Insurance Code article 3.50-4A, §2(d), which provides that TRS may consider "ability to service contracts, past experiences, financial stability, and other relevant criteria." The rule also requires contractors to administer enrollment, adjudication of claims and coordination of services for the applicable insurance plans and requires contractors to account for premiums collected and disbursed.

This section is adopted on an emergency basis to enable the retirement system to proceed with the issuance of a request for proposals and therefore comply with the requirements of the new law, which became effective September 1, 1999. The agency finds that requirements of state law (specifically those found in Insurance Code article 3.50-4A) require the adoption of this new rule on fewer than 30 days notice. The rule is simultaneously being proposed for permanent adoption.

The new section is adopted on an emergency basis under the Government Code, Chapter 825, §825.102, which authorizes the Board of Trustees of the Teacher Retirement System to adopt rules for the administration of the funds of the retirement system. Further, it is adopted under Insurance Code article 3.50-4A, including §2(d), which provides that competitive bidding shall be required under rules adopted by TRS and that the rules may provide criteria to determine qualified carriers. In addition, it is adopted under Insurance Code article 3.50-4A §§3(a) and (b), which provide that TRS shall adopt rules for the selection of contractors, that the rules must require the contractors to perform certain functions and that TRS may adopt other rules necessary to administer the program.

There are no other laws affected by this proposed rule.

§41.15. Requirements to Bid on Insurance For School District Employees and Retirees Under Article 3.50-4A of the Insurance Code.

(a) All contractors contracting and providing coverage under Article 3.50-4A of the Insurance Code shall:

(1) administer enrollment;

(2) adjudicate all claims related to the coverage, except for eligibility of participant under the statute which shall remain the responsibility of the Trustee;

(3) coordinate services under the insurance coverages provided under Insurance Code article 3.50-4A; and

(4) account for any premiums collected and disbursed under the coverages.

(b) To be eligible to bid on providing long-term care insurance, a carrier must:

(1) have had during the preceding calendar year at least $10 million of long-term care premium income;

(2) have capital and surplus of at least $500 million; and

(3) currently have at least three ratings within the top four rating categories as defined by the major insurance industry rating agencies. If a carrier is not rated, it may satisfy this requirement by showing that the carrier has twice the minimum financial requirements as stated in paragraphs (1) and (2) of this subsection.

(c) To be eligible to bid on providing optional permanent life insurance a carrier must:

(1) have had at least $200 million of individual life premium income during the last calendar year;

(2) have capital and surplus of at least $500 million; and

(3) currently have at least three ratings within the top four rating categories as defined by the major insurance industry rating agencies. If a carrier is not rated, it may satisfy this requirement by showing that the carrier has twice the minimum financial requirements as stated in paragraphs (1) and (2) of this subsection.

(d) To be eligible to bid on providing disability insurance a carrier must:

(1) have had during the preceding calendar year at least $50 million of short-term and long-term disability combined premium income;

(2) have capital and surplus of at least $500 million; and

(3) currently have at least three ratings within the top four rating categories as defined by the major insurance industry rating agencies. If not rated, a carrier may satisfy this requirement by showing that the carrier has twice the minimum financial requirements as stated in paragraphs (1) and (2) of this subsection.

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9909019
Charles Dunlap
Executive Director
Teacher Retirement System of Texas
Effective date: December 22, 1999
Expiration date: April 20, 2000
For further information, please call: (512) 391-2115

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PROPOSED RULES

Before an agency may permanently adopt a new or amended section or repeal an existing section, a proposal detailing the action must be published in the ***Texas Register*** at least 30 days before action is taken. The 30-day time period gives interested persons an opportunity to review and make oral or written comments on the section. Also, in the case of substantive action, a public hearing must be granted if requested by at least 25 persons, a governmental subdivision or agency, or an association having at least 25 members.

Symbology in proposed amendments. New language added to an existing section is indicated by the text being underlined. [Brackets] and ~~strike-through~~ of text indicates deletion of existing material within a section.

TITLE 1. ADMINISTRATION

Part 3. OFFICE OF THE ATTORNEY GENERAL

Chapter 55. CHILD SUPPORT ENFORCEMENT

Subchapter J. VOLUNTARY PATERNITY ACKNOWLEDGMENT PROCESS

1 TAC §§55.401 - 55.407

The Office of the Attorney General proposes new §§55.401 - 55.407, concerning voluntary acknowledgment of paternity. These new sections are being proposed to provide the opportunity for fathers and mothers to voluntarily establish paternity for their child(ren) through any local child support office of the Attorney General, Child Support Division; the Bureau of Vital Statistics; a local birthing hospital or birthing center; or any entity certified by the Office of the Attorney General to provide such services.

Howard G. Baldwin, Deputy Attorney General for Child Support, has determined that for the first five years these sections as proposed are in effect, there will be no fiscal implications for state or local government as a result of any replacement in these sections.

Mr. Baldwin has also determined that each year of the first five years the sections are in effect, the public benefit anticipated as a result of replacing or deleting the sections is a more standardized and efficient way to establish paternity. There will be no effect on small businesses. There are no anticipated economic costs to persons who are required to comply with the proposed sections.

Comments on these proposed sections may be submitted to Kathy Shafer, Child Support Enforcement Division, General Counsel Section, Office of the Attorney General, (physical address) 5500 East Oltorf, Austin, Texas,78741 or (mailing address) P.O. Box 12017, mail code 039, Austin, Texas, 78722-2017.

The new sections are proposed under the September 1, 1999 statutory changes, found in the Texas Family Code, Chapter 160, Subchapter C, Acknowledgment or Denial of Paternity.

The Code affected by these new sections is Health and Safety Code, Section 192, Record of Acknowledgment of Paternity.

§55.401. Scope.

Fathers and mothers who wish to voluntarily establish paternity for their child may do so through any local child support office of the Office of the Attorney General, Child Support Division; the state Bureau of Vital Statistics; a local birthing hospital or birthing center; or any entity certified by the Office of the Attorney General to provide such services. The Acknowledgment of Paternity must be executed according to the rules contained herein and under the Texas Family Code, Chapter 160, Subchapter C, Acknowledgment or Denial of Paternity. Entities that are required by law to provide paternity establishment services and entities that wish voluntarily to provide paternity establishment services must abide by the rules of this subchapter.

§55.402. Definitions.

The following words and terms, when used in this subchapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Acknowledgment of Paternity form - An agreement affirming parentage for a child signed by both the man claiming to be the father and the mother, that is executed on a form prescribed by the Bureau of Vital Statistics. The mother and father may sign separate acknowledgments before or after the birth of the child.

(2) Denial of Paternity form - A statement executed by a presumed father denying parentage of the child of whom he is presumed to be the father, on a form prescribed by the state.

(3) Certified entity - An agency, organization, or individual that is certified by the Office of the Attorney General to perform voluntary paternity establishment services. The certified entity must comply with all rules established for such certification.

(4) Presumed father - A man who is legally assumed to be the father of a child because he meets the criteria found under Texas Family Code §151.002.

§55.403. Forms.

The certified entities offering voluntary paternity establishment services may obtain the prescribed Acknowledgment of Paternity and Denial of Paternity forms by contacting the Bureau of Vital Statistics.

§55.404. Voluntarily Acknowledging Paternity.

(a) A man claiming to be the father and the mother may establish paternity before or after the birth of their child by voluntarily acknowledging paternity through a certified entity providing such services. The mother and father must read the Acknowledgment of Paternity form. In addition, both must listen to or view a video presentation of the rights and responsibilities of a parent, and alternatives to and legal consequences of acknowledging or denying paternity. Both the mother and father, separately or together, must then:

(1) complete an Acknowledgment of Paternity form;

(2) sign it before a witness;

(3) return the form to a certified entity.

(b) Both mother and father must present to the certified entity a valid driver license or another document (preferably a photo I.D.) to verify identity.

(c) The certified entity is responsible for filing the Acknowledgment of Paternity form with the Bureau of Vital Statistics.

§55.405. Denial of Paternity Form.

If the mother declares in the Acknowledgment of Paternity form that there is a presumed father of the child, the acknowledgment must be accompanied by a Denial of Paternity form signed by the presumed father, unless the presumed father is the man who is acknowledging paternity. The Bureau of Vital Statistics will not accept the Acknowledgment of Paternity form for filing without the Denial of Paternity form, unless the presumed father is the man who has signed the Acknowledgment of Paternity form.

§55.406. Entities that May Provide Paternity Establishment Services.

All public and private birthing hospitals, all birthing centers, and the state Bureau of Vital Statistics are required to provide voluntary paternity establishment services, but only after being certified by the Office of the Attorney General. The following entities may provide voluntary paternity establishment services at their option, but only after being certified by the Office of the Attorney General:

(1) local birth registrars;

(2) public health clinics;

(3) private health care providers;

(4) certified nurse midwives;

(5) documented midwives;

(6) agencies providing assistance or services under Title IV, Part A of the Social Security Act, agencies providing food stamp eligibility service, and agencies providing child support enforcement (IV-D) services;

(7) Head Start, child care facilities, and individual child care providers;

(8) community action agencies and community action programs;

(9) secondary education schools;

(10) legal aid agencies;

(11) private attorneys; and

(12) any public or private health, welfare or social services organization.

§55.407. Certification.

All birthing hospitals, all birthing centers, the state Bureau of Vital Statistics, and each certified entity must have staff who:

(1) provide the mother and father the opportunity to voluntarily acknowledge paternity;

(2) provide the mother and father an opportunity to speak, either by telephone or in person, with staff who are trained to clarify information and answer questions about paternity establishment;

(3) are trained by Office of the Attorney General staff at least once yearly on the requirements for voluntarily establishing paternity. (The training is not to exceed eight (8) hours at locations throughout the state established by the Office of the Attorney General and Bureau of Vital Statistics.)

(4) use only the Acknowledgment of Paternity and Denial of Paternity forms promulgated by the Bureau of Vital Statistics.

(5) use the brochures and training manuals, including the oral and written information, provided by the Office of the Attorney General and the Bureau of Vital Statistics.

(6) are periodically evaluated by the Office of the Attorney General.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 27, 1999.

TRD-9909041
Elizabeth Robinson
Assistant Attorney General
Office of the Attorney General
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 460-6134

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TITLE 7. BANKING AND SECURITIES

Part 1. FINANCE COMMISSION OF TEXAS

Chapter 1. CONSUMER CREDIT COMMISSION

Subchapter B. MISCELLANEOUS

7 TAC §§1.301-1.305

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Finance Commission of Texas or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

The Finance Commission of Texas (the commission) proposes the repeal of §§1.301 - 1.305. This repeal is necessary because the sections that are proposed for repeal relate to Appeal From Orders to Desist or To Refrain; Notice in Written Contracts; Annual Fee by Holders, Creditors, and Assignees; Notice and Processing Periods for Permit Applications; and Interpretations and Advisory Letters.

These sections are being reviewed and reproposed with changes in a new section of the Texas Administrative Code. Section 1.301 and 1.304 are not being reproposed as the subject matter of these rules is adequately covered by other rules already in effect. The new rules are being published simultaneously for comment in the *Texas Register*.

Leslie L. Pettijohn, Consumer Credit Commissioner, has determined that for the first five-year period of the repeal as proposed will be in effect, there will be no fiscal implications for state or local government as a result of administering or enforcing the repeal.

Ms. Pettijohn also has determined that for each year of the first five-year period the repeal as proposed will be in effect, the public benefit anticipated as a result of the repeal is the removal of unenforceable and obsolete regulations which will provide space for replacement rules. These is no anticipated cost to persons who are required to comply with the repeal as proposed. There will be no adverse economic effect on small businesses.

Comments on the proposed repeal may be submitted in writing to Leslie L. Pettijohn, Consumer Credit Commissioner, 2601 North Lamar Boulevard, Austin, Texas 78705-4207.

The repeal is proposed under Texas Finance Code, §11.304, which authorizes the Finance Commission to adopt rules to enforce Title 4. The repeal will not be adopted until the proposed replacement sections are adopted.

The statutory provisions (as currently in effect) affected by the proposed repeal are Texas Finance Code, Chapters 345, 347, 348, and the rest of Title 4.

§1.301. Appeals from Orders to Desist or to Refrain.

§1.302. Notice in Written Contracts.

§1.303. Annual Fee by Holders, Creditors, and Assignees.

§1.304. Notice and Processing Periods for Permit Applications.

§1.305. Interpretations and Advisory Letters.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 27, 1999.

TRD-9909045
Leslie L. Pettijohn
Commissioner
Finance Commission of Texas
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 936-7640

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Subchapter P. REGISTRATION OF RETAIL CREDITORS

7 TAC §§1.901, 1.902, 1.911

The Finance Commission of Texas (the commission) proposes new §§1.901, 1.902, and 1.911, concerning notice in written contracts; annual registration fees by holders, creditors, and assignees; and interpretations and advisory letters. The proposal is part of a rule review conducted in accordance with HB 1, Article IX, Section 167. Simultaneously, the Finance Commission is repealing the former rules and adopting these rules in their place. These rules being repealed were reviewed and those being proposed to be adopted here were evaluated and an assessment made that the reasons for (re)adopting the rule continues to exist. The primary changes from the former rules are organizational in nature or to appropriately identify the new statutory citations of the Texas Finance Code.

Section 1.901 addresses the written notice required in retail installment sales contracts. The required notice provides consumes with information on how to contact the creditor or the regulator for information.

Section 1.902 prescribes the procedures for processing the annual registration fees.

Section 1.911 identifies the appropriate terms and procedures for interpretations approved by the Finance Commission and advisory opinions issued by the Office of Consumer Credit Commissioner.

Leslie L. Pettijohn, Consumer Credit Commissioner has determined that for the first five- year period these rules will be in effect, there will be no fiscal implications for state or local government as a result of administering or enforcing these rules.

Commissioner Pettijohn also has determined that for each year of the first five-year period these rules will be in effect, the public benefit anticipated as a result of the adoption of the new rules will be to more adequately inform the public of the procedures pertaining to registration of creditors and the process of obtaining interpretations and opinions.

Comments on the proposed adoption of the new sections may be submitted in writing to Leslie L. Pettijohn, Consumer Credit Commissioner, 2601 North Lamar Boulevard, Austin, Texas 78705-4207.

The new sections are proposed under Texas Finance Code, §11.304, which authorizes the Finance Commission to adopt rules to enforce Title 4 of the Texas Finance Code.

Texas Finance Code, Chapters 345, 347, and 348 as well as the remainder of Title 4 are affected by these proposed new sections.

§1.901. Consumer Notifications.

(a) When a written contract or agreement is made under the authority of Texas Finance Code, Chapter 345, 347, or 348, the contract must contain as a separate section or otherwise conspicuously set out from the surrounding written material, the following statement: "To contact (insert authorized business name of retail seller, creditor, or holder as appropriate) about this account call (insert telephone number of retail seller, creditor, or holder as appropriate). This contract is subject in whole or in part to Texas law which is enforced by the Consumer Credit Commissioner, 2601 N. Lamar Blvd., Austin, Texas 78705-4207; (800) 538- 1579; (512) 936-7600, and can be contacted relative to any inquiries or complaints."

(b) The telephone number of the retail seller, creditor, or holder may be printed in conjunction with the name and address of the retail seller, creditor, or holder elsewhere on the contract or agreement provided the notice in subsection (a) of this section is amended to direct the reader's attention to the area of the contract where the telephone number may be found.

(c) A retail seller as that term is defined in Chapter 345 or in Chapter 348 or a creditor as that term is defined in Chapter 347 may continue to use the notice as previously required by this section without modification for a period of one year following the effective date of this rule.

§1.902. Annual Registration Fees.

(a) An annual registration fee is required for each location operated by a retail seller, creditor, holder or assignee.

(b) An annual fee is required under the provisions of Texas Finance Code §345.351, §347.451 or §348.401 and shall be payable as follows:

(1) a retail seller, creditor, holder, or assignee shall pay a registration fee for every chapter under which business is conducted.

(2) retail seller, holder, creditor, or assignee who begins business under Texas Finance Code, Chapter 345, 347, or 348 shall pay the annual fee within sixty days after the first day of commencing regulated operations.

(3) The annual fee for each subsequent calendar year shall be due and payable by October 31st of each year.

(4) The registration is not transferable between locations. Each new location must comply with the provisions in paragraph (2) of this subsection.

(5) No annual fee is required for a location operated by a retail seller, creditor, holder, or assignee operating under the provisions of Texas Finance Code, Chapter 345, 347, or 348 provided the personnel at the location are not conducting regulated business with the consumer (e.g. storage, web-hosting, or data processing facility).

(c) Evidence of registration. The Office of Consumer Credit Commissioner will issue a decal evidencing registration under the provisions of Texas Finance Code, Chapter 345, 347, or 348 and this rule. This decal shall be:

(1) Affixed to door or window of the principal entrance; or

(2) Displayed in a prominent location readily visible to the consumer.

§1.911. Interpretations and Advisory Letters.

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Advisory letter–A letter by the commissioner or a member of the staff of the Office of Consumer Credit Commissioner providing an informal advisory response to an inquiry concerning provisions of the Texas Finance Code, Title 4, Subtitles A or B and is not an interpretation as defined in paragraph (3) of this subsection.

(2) Commissioner–The commissioner of the Office of Consumer Credit Commissioner.

(3) Interpretation–A letter issued by the consumer credit commissioner and approved by the Finance Commission of Texas pursuant to Texas Civil Statutes, Texas Finance Code §14.108 interpreting a provision of Title 4, Subtitle A or B in light of certain relevant facts by the requestor.

(b) Procedures for Finance Commission of Texas interpretations. Any person may submit a request for an interpretation. All requests must be directed to the commissioner and contain the following items:

(1) An explicitly statement that an interpretation approved by the Finance Commission of Texas is desired.

(2) A concise description of the contemplated transaction or activity contemplated, the legal issue raised, and all facts necessary to reach a conclusion in the matter.

(3) A statement whether or not, to the best of the requester's knowledge, the issue to be considered is an issue in pending litigation. Matters in litigation will not ordinarily be answered.

(4) A fee of $300 will be charged for an interpretation to compensate the agency for the expense involved in researching and answering the request. A payment of $300 should be submitted with the request. The commission may determine and remit a partial refund if deemed applicable. The commission may waive the fee.

(5) Additional information. A requestor should also identify each provision of law involved, and indicate the writer's opinion of how the legal issues should be resolved, and the basis for that opinion, including an analysis of any relevant court decisions, as well as, all prior interpretations to which the request relates.

(6) Processing time. Within ten business days of receipt of a valid request pursuant to this subsection, the request will be filed with the Texas Register for publication. Upon publication in the *Texas Register*, any party may within 30 calendar days submit briefs or proposals pertaining to the request. The agency will draft an interpretation or a response and present it to the Finance Commission of Texas for their consideration. Within ten business days of an action of the Finance Commission of Texas, a summary of the interpretation or the response will be filed with the Texas Register for publication. Copies of interpretations or responses shall contain a notation of approval and the date of action by the Finance Commission of Texas.

(c) Office of Consumer Credit Commissioner advisory letters. Each advisory letter shall contain the following notation: "THIS ADVISORY LETTER IS NOT AN INTERPRETATION APPROVED BY THE FINANCE COMMISSION OF TEXAS PURSUANT TO TEXAS FINANCE CODE, §14.108. If an interpretation approved by the Finance Commission of Texas is desired, then an interpretation should be requested pursuant to the procedures set forth in 7 Texas Administrative Code §1.911(b)".

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 27, 1999.

TRD-9909044
Leslie L. Pettijohn
Commissioner
Finance Commission of Texas
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 936-7640

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TITLE 22. EXAMINING BOARDS

Part 15. TEXAS STATE BOARD OF PHARMACY

Chapter 281. ADMINISTRATIVE PRACTICE AND PROCEDURES

Subchapter A. GENERAL PROVISIONS

22 TAC §281.18

The Texas State Board of Pharmacy proposes new §281.18, concerning Reporting Professional Liability Claims. The new rule, if adopted, will implement the provisions of Senate Bill 730 (76th Legislative Session) regarding the reporting of professional liability claims to the Texas State Board of Pharmacy.

Gay Dodson, R.Ph., Executive Director/Secretary, has determined that, for the first five-year period the rule is in effect, there will be fiscal implications for the state as a result of enforcing or administering the rule. There are no anticipated fiscal implications for local government. The fiscal implications for the state are based on the cost of enforcing and/or administering the rule by the Texas State Board of Pharmacy. Costs for the first year of the new program will include setup costs as well as costs to administer the program. The estimated cost to the Texas State Board of Pharmacy for the next five years will be: FY2000–$232,175; FY2001–$160,010; FY2002–$160,010; FY2003–$160,010; and FY2004–$160,010.

Ms. Dodson has determined that, for each year of the first five-year period the rule will be in effect, the public benefit anticipated as a result of enforcing the rule will be the protection of the public by identifying licensees who have had malpractice claims filed against them and by taking action against the licensee when appropriate. In most cases, the malpractice insurance carrier will be filing the report with the agency. The costs/fiscal implications to small and large businesses or to other entities who are required to comply with this section cannot be determined by the agency due to the variability in the internal policies of malpractice insurance carriers. It is anticipated that the report form will take 10 to 15 minutes to complete but could vary greatly depending on internal policies of the insurance carrier.

Comments on the proposal may be submitted to Steve Morse, R.Ph., Director of Compliance, Texas State Board of Pharmacy, 333 Guadalupe Street, Suite 3-600, Box 21, Austin, Texas, 78701-3942.

The new section is proposed under §42 of the Texas Pharmacy Act (Article 4542a-1, Texas Civil Statutes), as added in Senate Bill 730 by the 76th Legislature, and §554.051 of the Occupations Code. The Board interprets §42 of the Texas Pharmacy Act as authorizing the agency to adopt rules to for reporting professional liability claims. The Board interprets §554.051 of the Occupations Code as authorizing the agency to adopt rules for the proper administration and enforcement of the Act.

The statutes affected by this rule: Texas Civil Statutes, Article 4542a-1, now codified as Occupations Code Subtitle J.

§281.18. Reporting Professional Liability Claims.

(a) Reporting responsibilities.

(1) Every insurer or other entity providing pharmacist's professional liability insurance, pharmacy technician professional and supplemental liability insurance, or druggist's professional liability insurance covering a pharmacist, pharmacy technician, or pharmacy license holder in this state shall submit to the board the information described in subsection (b) of this section at the time prescribed.

(2) The information shall be provided with respect to a notice of claim letter or complaint filed against an insured in a court, if the notice or complaint seeks damages relating to the insured's conduct in providing or failing to provide appropriate service within the scope of pharmaceutical care or services, and with respect to settlement of a claim or lawsuit made on behalf of the insured.

(3) If a pharmacist, pharmacy technician, or a pharmacy licensed in this state does not carry or is not covered by pharmacist's professional liability insurance, pharmacy technician professional and supplemental liability insurance, or druggist's professional liability insurance, or if a pharmacist, pharmacy technician, or a pharmacy licensed in this state is insured by a non-admitted carrier or other entity providing pharmacy professional liability insurance that does not report under this Act, the duty to report information under subsection (b) of this section is the responsibility of the particular pharmacist, pharmacy technician, or pharmacy license holder.

(4) For the purposes of this section a professional liability claim or complaint shall be defined as a cause of action against a pharmacist, pharmacy, or pharmacy technician for conduct in providing or failing to provide appropriate service within the scope of pharmaceutical care or services, which proximately results in injury to or death of the patient, whether the patient's claim or cause of action sounds in tort or contract, to include pharmacist's interns, pharmacy residents, supervising pharmacists, on-call pharmacists, consulting pharmacists.

(b) Information to be reported and due dates.

(1) Initial report. Not later than the 30th day after receipt of the notice of claim letter or complaint by the insurer if the insurer has the duty to report, or by the pharmacist, pharmacy technician, or a pharmacy if the license holder has the duty to report, the following information must be furnished to the board on a form provided by the board:

(A) the name and address of the insurer;

(B) the name and address of the insured and type of license or registration held (pharmacist, pharmacy or pharmacy technician):

(C) the insured's Texas pharmacist or pharmacy license number or pharmacy technician registration number;

(D) certification, if applicable;

(E) the policy number;

(F) name(s) of plaintiff(s);

(G) date of injury;

(H) county of injury;

(I) cause of injury, e.g., dispensing error;

(J) nature of injury;

(K) type of action, e.g., claim only or lawsuit;

(L) name and phone number of the person filing the report; and

(M) a copy of the notice of claim letter or the lawsuit filed in court.

(2) Follow-up report. Within 105 days after disposition of the claim, the following information must be provided to the board on a form provided by the board:

(A) the name and address of the insured and type of license or registration held (pharmacist, pharmacy or pharmacy technician):

(B) the insured's Texas pharmacist or pharmacy license number or pharmacy technician registration number;

(C) name(s) of plaintiff(s);

(D) date of disposition;

(E) type of disposition, e.g., settlement, judgment;

(F) amount of disposition;

(G) whether an appeal has been taken and by which party; and

(H) name and phone number of the person filing the report.

(3) Definition. For the purpose of this section, disposition of a claim shall include circumstances where a court order has been entered, a settlement agreement has been reached, or the complaint has been dropped or dismissed.

(c) Report format

(1) Separate reports are required for each defendant licensee or registrant.

(2) The information shall be reported on a form provided by the board.

(3) A court order or settlement agreement may be submitted as an attachment to the follow-up report.

(d) Claims not required to be reported. Examples of claims that are not required to be reported under this section are the following:

(1) product liability claims (i.e., where a licensee invented a medical device which may have injured a patient but the licensee has no personal pharmacist-patient relationship with the specific patient claiming injury by the device);

(2) antitrust allegations;

(3) allegations involving improper peer review activities;

(4) civil rights violations; or

(5) allegations of liability for injuries occurring on a licensee's property, but not involving a breach of duty (i.e., slip and fall accidents).

(e) Liability. An insurer reporting under this section, its agents or employees, or the board or its employees or representatives are not liable for damages in a suit brought by any person or entity for reporting as required by this section or for any other action taken under this section.

(f) Limit on use of information reported.

(1) Information submitted to the board under this section and the fact that the information has been submitted to the board may not be:

(A) offered in evidence or used in any manner in the trial of a suit described in this section; or

(B) used in any manner to determine the eligibility or credentialing of a pharmacy to participate in a health insurance plan defined by the Insurance Code.

(2) A report received by the board under this section is not a complaint for which a board investigation is required except that the board shall review the information relating to a pharmacist, pharmacy technician, or pharmacy license holder against whom at least three professional liability claims have been reported within a five-year period in the same manner as if a complaint against the pharmacist, pharmacy technician, or pharmacy license holder had been made under Chapter 555 of the Act. The board may initiate an investigation of pharmacist, pharmacy technician, or pharmacy license holder based on the information received under this section.

(3) The information received under this section may be used in any board proceedings as the board deems necessary.

(g) Confidentiality. Information submitted under this section is confidential, except as provided in subsection (f)(3) of this section, and is not subject to disclosure under Chapter 552, Government Code.

(h) Penalty. The Texas Department of Insurance may impose on any insurer subject to this Act sanctions authorized by §§82.051-82.055 (formerly §7, Article 1.10) of the Texas Insurance Code, if the insurer fails to report information as required by this section.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 23, 1999.

TRD-9909022
Gay Dodson, R.Ph.
Executive Director/Secretary
Texas State Board of Pharmacy
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 305-8028

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Subchapter B. GENERAL PROCEDURES IN A CONTESTED CASE

22 TAC §281.57

The Texas State Board of Pharmacy proposes new §281.57, concerning Disciplinary Guidelines. The new rule, if adopted, will provide guidance and promote consistency for sanctions in contested cases.

Gay Dodson, R.Ph., Executive Director/Secretary, has determined that, for the first five-year period the rule is in effect, there will be no fiscal implications for state or local government as a result of enforcing or administering the rule.

Ms. Dodson has determined that, for each year of the first five-year period the rule will be in effect, the public benefit anticipated as a result of enforcing the rule will be to: (1) provide guidance and a framework of analysis for administrative law judges in the making of recommendations in contested licensure and disciplinary matters; (2) promote consistency in the exercise of sound discretion by board members in the imposition of sanctions in disciplinary matters; and (3) provide guidance for board members for the resolution of potentially contested matters. There are no anticipated economic costs to small or large businesses or to other entities who are required to comply with this section as proposed.

Comments on the proposal may be submitted to Steve Morse, R.Ph., Director of Compliance, Texas State Board of Pharmacy, 333 Guadalupe Street, Suite 3-600, Box 21, Austin, Texas, 78701-3942.

The new section is proposed under §554.002 and §554.051 of the Texas Pharmacy Act (Subtitle J, Chapters 551-564, Occupations Code). The Board interprets §554.002 of the Texas Pharmacy Act as authorizing the agency to regulate the practice of pharmacy by enforcing the provisions of the Act relating to the suspension, revocation, retirement, or restriction of a license to practice pharmacy or to operate a pharmacy or the imposition of an administrative penalty or reprimand on a license holder. The Board interprets §554.051 of the Texas Pharmacy Act as authorizing the agency to adopt rules for the proper administration and enforcement of the Act.

The statutes affected by this rule: Occupations Code, Subtitle J.

§281.57. Disciplinary Guidelines.

(a) Purpose. This section is promulgated to:

(1) provide guidance and a framework of analysis for administrative law judges in the making of recommendations in contested licensure and disciplinary matters;

(2) promote consistency in the exercise of sound discretion by board members in the imposition of sanctions in disciplinary matters; and

(3) provide guidance for board members for the resolution of potentially contested matters.

(b) Limitations. This chapter shall be construed and applied so as to preserve board member discretion in the imposition of sanctions and remedial measures pursuant to Chapter 566, Occupations Code. This chapter shall be further construed and applied so as to be consistent with the Act, and shall be limited to the extent as otherwise proscribed by statute and board rule.

(c) Aggravation. The following may be considered as aggravating factors so as to merit more severe or more restrictive action by the board:

(1) patient harm and the severity of patient harm;

(2) economic harm to any individual or entity and the severity of such harm;

(3) environmental harm and severity of such harm;

(4) increased potential for harm to the public;

(5) attempted concealment of misconduct;

(6) premeditated misconduct;

(7) intentional misconduct;

(8) motive;

(9) prior misconduct of a similar or related nature;

(10) disciplinary history;

(11) prior written warnings or written admonishments from any government agency or official regarding statutes or regulations pertaining to the misconduct;

(12) violation of a board order;

(13) failure to implement remedial measures to correct or mitigate harm from the misconduct;

(14) lack of rehabilitative potential or likelihood for future misconduct of a similar nature; and

(15) relevant circumstances increasing the seriousness of the misconduct.

(d) Extenuation and Mitigation. The following may be considered as extenuating and mitigating factors so as to merit less severe or less restrictive action by the board:

(1) absence of patient harm;

(2) absence of economic harm to any individual or entity;

(3) absence of environmental harm;

(4) absence of potential harm to the public;

(5) self-reported and voluntary admissions of misconduct;

(6) absence of premeditation to commit misconduct;

(7) absence of intent to commit misconduct;

(8) motive;

(9) absence of prior misconduct of a similar or related nature;

(10) absence of a disciplinary history;

(11) implementation of remedial measures to correct or mitigate harm from the misconduct;

(12) rehabilitative potential;

(13) prior community service and present value to the community;

(14) relevant circumstances reducing the seriousness of the misconduct; and

(15) relevant circumstances lessening responsibility for the misconduct.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 23, 1999.

TRD-9909023
Gay Dodson, R.Ph.
Executive Director/Secretary
Texas State Board of Pharmacy
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 305-8028

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Chapter 291. PHARMACIES

Subchapter A. ALL CLASSES OF PHARMACIES

22 TAC §291.27

The Texas State Board of Pharmacy proposes new §291.27, concerning Pharmacy Residency Programs. The new rule, if adopted, will implement the provisions of Senate Bill 931 (76th Legislative Session) regarding recognizing and approving pharmacy residency programs.

Gay Dodson, R.Ph., Executive Director/Secretary, has determined that, for the first five-year period the rule is in effect, there will be no fiscal implications for state or local government as a result of enforcing or administering the rule.

Ms. Dodson has determined that, for each year of the first five-year period the rule will be in effect, the public benefit anticipated as a result of enforcing the rule will be the protection of the public and increased public confidence in the practice of pharmacy by setting standards which recognize and approve pharmacy residency programs. Of the 32 currently operating pharmacy residency programs identified by the agency, 28 already meet the requirements established by this rule. Therefore, there will be minimal additional economic costs to small and large businesses and to other entities who are required to comply with this section.

Comments on the proposal may be submitted to Steve Morse, R.Ph., Director of Compliance, Texas State Board of Pharmacy, 333 Guadalupe Street, Suite 3-600, box 21, Austin, Texas, 78701-3942.

The new section is proposed under §17(a) of the Texas Pharmacy Act (Article 4542a-1, Texas Civil Statutes), as amended by the 76th Legislature, and §554.051 of the Occupations Code. The Board interprets §17(a) of the Texas Pharmacy Act as authorizing the agency to specify standards for recognizing and approving pharmacy residency programs for the purpose of Subchapter T, Chapter 61, Education Code. The Board interprets §554.051 of the Occupations Code as authorizing the agency to adopt rules for the proper administration and enforcement of the Act.

The statutes affected by this rule: Texas Civil Statutes, Article 4542a-1, now codified as Occupations Code Subtitle J.

§291.27. Pharmacy Residency Programs.

For the purposes of Subchapter T, Chapter 61, Education Code, the standards for pharmacy residency programs shall be the standards required by the American Society of Health-System Pharmacists' Commission on Credentialing. The pharmacy residency programs approved by the Board shall be published periodically in the minutes of the Board.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 23, 1999.

TRD-9909024
Gay Dodson, R.Ph.
Executive Director
Texas State Board of Pharmacy
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 305-8028

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22 TAC §291.29

The Texas State Board of Pharmacy proposes new §291.29, concerning Special Exemption from Pharmacy Technician Certification Requirements. The new rule, if adopted, will implement the provisions of Senate Bill 730 (76th Legislative Session) regarding exemptions from the requirement for pharmacy technicians to become certified.

Gay Dodson, R.Ph., Executive Director/Secretary, has determined that, for the first five-year period the rule is in effect, there will be fiscal implications for the state as a result of enforcing or administering the rule. There are no anticipated fiscal implications for local government. The fiscal implications for the state are based on the cost of enforcing or administering the rule by the Texas State Board of Pharmacy. The agency anticipates the receipt of up to 1500 petitions the first year and 90 petitions for each of the second through fifth years. After 5 years, the exemption process will cease. Costs for the first year of the program will include setup costs as well as costs to administer the program. The estimated cost to the Texas State Board of Pharmacy for the next five years will be: FY2000–$25,380; FY2001–$803; FY2002–$803; FY2003–$803; and FY2004–$803.

Ms. Dodson has determined that, for each year of the first five-year period the rule will be in effect, the public benefit anticipated as a result of enforcing the rule will be to allow the continued use of non-certified, experienced pharmacy technicians and to allow pharmacies in counties of less than 10,000 population to continue to use non-certified pharmacy technicians. Both exemptions cease on January 1, 2006. The exemptions allow the affected pharmacies additional time to get their technicians certified. The economic cost to small and large businesses or to entities who are required to comply with this section will largely be determined by the amount of time necessary to gather the required information, complete the petition, and forward the petition to the agency. It is anticipated that the time necessary to gather the information required and to complete the petition will average approximately one hour. Assuming that the pharmacy technician's time accounts for 3/4 of the hour and a pharmacist's time for the remaining 1/4 hour, the agency estimates a cost of $15.13 per petition based on salaries of $32/hr for a pharmacist and $9.50/hr for a pharmacy technician.

Comments on the proposal may be submitted to Steve Morse, R.Ph., Director of Compliance, Texas State Board of Pharmacy, 333 Guadalupe Street, Suite 3-600, box 21, Austin, Texas, 78701-3942.

The new section is proposed under §20(A) of the Texas Pharmacy Act (Article 4542a-1, Texas Civil Statutes), as added by the 76th Legislature, and §554.051 of the Occupations Code. The Board interprets §20(A) of the Texas Pharmacy Act as authorizing the agency to grant exemptions to the pharmacy technician certification requirements. The Board interprets §554.051 of the Occupations Code as authorizing the agency to adopt rules for the proper administration and enforcement of the Act.

The statutes affected by this rule: Texas Civil Statutes, Article 4542a-1, now codified as Occupations Code Subtitle J.

§291.29. Special Exemption from Pharmacy Technician Certification Requirements

(a) Pharmacy technicians who, on September 1, 2001, will have been employed as a pharmacy technician in this state for at least 10 years.

(1) Eligibility. A pharmacy technician may petition the board for a special exemption from the certification requirements established by §20A of the Act if the technician has been continuously employed at a pharmacy in this state since September 1, 1991.

(2) Petition process.

(A) A pharmacy technician shall petition the board for the special exemption on a form provided by the board. The petition shall contain the following:

(i) the name of the pharmacy technician;

(ii) the name, address, and license number (if known) of the pharmacies where the pharmacy technician has been employed;

(iii) dates of employment in each pharmacy;

(iv) a statement signed by the pharmacy technician attesting that the information provided in the petition is true and correct; and

(v) a statement signed by the pharmacist-in-charge of the pharmacy attesting that the pharmacy technician has been continuously employed as a pharmacy technician/supportive person at a pharmacy in this state since September 1, 1991.

(B) After review of the petition and/or verification of the employment record, the pharmacy technician shall be notified in writing of approval or denial of the petition. If the petition is approved, the pharmacy technician will be sent a special exemption certificate which shall be displayed at the pharmacy named in the petition.

(3) Limitation of exemption.

(A) After January 1, 2001, pharmacy technicians exempted from certification may not perform any of the duties restricted to a certified pharmacy technician.

(B) All exemptions from certification expire on January 1, 2006. After January 1, 2006, pharmacy technicians exempted from certification shall cease performing the duties of a pharmacy technician until such time as they become certified pharmacy technicians.

(b) Pharmacy technicians working in counties with a population of 10,000 or less.

(1) Eligibility. A pharmacy technician may petition the board for a special exemption from the certification requirements established by §20A of the Act if the technician works in a county with a population of 10,000 or less.

(2) Petition process.

(A) A pharmacy technician shall petition the board for the special exemption on a form provided by the board. The petition shall contain the following:

(i) the name of the pharmacy technician;

(ii) the name, address, and license number of the pharmacy where the pharmacy technician is employed;

(iii) name of the county in which the pharmacy is located and the most recent official population estimate for the county from the Texas State Data Center;

(iv) a statement signed by the pharmacy technician attesting that the information provided in the petition is true and correct; and

(v) a statement signed by the pharmacist-in-charge of the pharmacy attesting that the pharmacy technician is employed as a pharmacy technician at the pharmacy.

(B) After review of the petition, the pharmacy technician shall be notified in writing of approval or denial of the petition. If the petition is approved, the pharmacy technician will be sent a special exemption certificate which shall be displayed at the pharmacy named in the petition.

(3) Limitation of exemption.

(A) After January 1, 2001, pharmacy technicians exempted from certification may not perform any of the duties restricted to a certified pharmacy technician.

(B) All exemptions from certification expire on January 1, 2006. After January 1, 2006, pharmacy technicians exempted from certification shall cease performing the duties of a pharmacy technician until such time as they become certified pharmacy technicians.

(C) The exemption granted under this section is only applicable for the pharmacy noted in the petition. Should the pharmacy technician cease employment at the pharmacy or change employment the exemption is canceled and the pharmacy technician shall comply with the certification requirements.

(D) If the population of the county increases to a point which exceeds a population of 10,000, the Board shall cancel the exemption. The pharmacy technician and the pharmacist-in-charge of the pharmacy will be notified when an exemption is canceled.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 23, 1999.

TRD-9909025
Gay Dodson, R.Ph.
Executive Director/Secretary
Texas State Board of Pharmacy
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 305-8028

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Subchapter B. COMMUNITY PHARMACY (CLASS A)

22 TAC §§291.31-291.34, 291.36

The Texas State Board of Pharmacy proposes amendments to §291.31, concerning Definitions, §291.32, concerning Personnel, §291.33, concerning Operational Standards, §291.34, concerning Records, and §291.36, concerning Class A Pharmacies Compounding Sterile Pharmaceuticals. The amendments, if adopted, will: (1) implement the recommendations of the Task Force on Non-Resident Pharmacies and Pharmacy Automation; and (2) make changes as a result of the rule review of §§291.31-291.34.

Gay Dodson, R.Ph., Executive Director/Secretary, has determined that, for the first five-year period the rule is in effect, there will be no additional fiscal implications for state or local government as a result of enforcing or administering the rule.

Ms. Dodson has determined that, for each year of the first five-year period the rule will be in effect, the public benefit anticipated as a result of enforcing the rule will be to protect the public through the effective control and regulation of the use of automation in pharmacies and to update and clarify currently existing rules. The automation component of the rules permits use of new technology which previously was restricted. Since licensees are not mandated to use the new technology, there is no additional fiscal impact for small or large businesses or to other entities.

The rule review component of the rules requires pharmacies to have hot running water. Since not all pharmacies currently have hot running water, there will be an economic cost for the small and large businesses and entities required to comply with this section. For the very few pharmacies without hot running water, the anticipated cost to comply could range up to several hundred dollars depending on the water heating device selected and what is necessary to install the device. There are no further anticipated economic costs to small or large businesses or to other entities who are required to comply with this section.

Comments on the proposal may be submitted to Steve Morse, R.Ph., Director of Compliance, Texas State Board of Pharmacy, 333 Guadalupe Street, Suite 3-600, Box 21, Austin, Texas, 78701-3942.

The amendments are proposed under §§554.002, 554.051, and 554.005 of the Texas Pharmacy Act (Subtitle J, Chapters 551-564, Occupations Code). The Board interprets §554.002 of the Texas Pharmacy Act as authorizing the agency to protect the public through the effective control and regulation of the practice of pharmacy. The Board interprets §554.051 of the Texas Pharmacy Act as authorizing the agency to adopt rules for the proper administration and enforcement of the Act. The Board interprets §554.005 of the Texas Pharmacy Act as authorizing the agency to regulate the delivery or distribution of prescription drugs as they relate to the practice of pharmacy and specify the minimum standards for the maintenance of prescription drug records.

The statutes affected by this rule: Occupations Code, Subtitle J.

§291.31. Definitions.

The following words and terms, when used in this subchapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Accurately as prescribed–Dispensing, delivering, and/or distributing a prescription drug order:

(A)-(B) (No change.)

(C) with correct labeling (including directions for use) as ordered by the practitioner. Provided, however, that nothing herein shall prohibit pharmacist substitution if substitution is conducted in strict accordance with applicable laws and rules, including Chapters 562 and 563 [~~§40~~] of the Texas Pharmacy Act.

(2) Act–The Texas Pharmacy Act, Chapters 551-566, Occupations Code, [~~Texas Civil Statutes, Article 4542a-1,~~] as amended.

(3) (No change.)

(4) Automated compounding or counting device [~~Automated drug dispensing system~~]–An automated device that compounds, measures, counts, and/or packages[~~, and/or labels~~] a specified quantity of dosage units of [~~for~~] a designated drug product.

(5) Automated pharmacy dispensing systems–a mechanical system that performs operations or activities, other than compounding or administration, relative to the storage, packaging, counting, labeling, dispensing, and distribution of medications, and which collects, controls, and maintains all transaction information. "Automated pharmacy dispensing systems" does not mean "Automated compounding or counting devices" or "Automated medication supply devices."

(6) [~~(5)~~] Board–The Texas State Board of Pharmacy.

(7) [~~(6)~~] Carrying out or signing a prescription drug order–The completion of a prescription drug order presigned by the delegating physician, or the signing of a prescription by an advanced practice nurse or physician assistant after the person has been designated with the Texas State Board of Medical Examiners by the delegating physician as a person delegated to sign a prescription. The following information shall be provided on each prescription:

(A) patient's name and address;

(B) name, strength, and quantity of the drug to be dispensed;

(C) directions for use;

(D) the intended use of the drug, if appropriate;

(E) the name, address, and telephone number of the physician;

(F) the name, address, telephone number, and identification number of the advanced practice nurse or physician assistant completing the prescription drug order;

(G) the date; and

(H) the number of refills permitted.

(8) [~~(7)~~] Certified Pharmacy Technician–A pharmacy technician who:

(A) has completed the pharmacy technician training program of the pharmacy;

(B) has taken and passed the National Pharmacy Technician Certification Exam or other examination approved during an open meeting by the Board; and

(C) maintains a current certification with the Pharmacy Technician Certification Board or any other entity providing an examination approved by the Board.

(9) [~~(8)~~] Component–Any ingredient intended for use in the compounding of a drug product, including those that may not appear in such product.

(10) [~~(9)~~] Compounding–The preparation, mixing, assembling, packaging, or labeling of a drug or device:

(A) as the result of a practitioner's prescription drug order or initiative based on the practitioner-patient-pharmacist relationship in the course of professional practice;

(B) in anticipation of prescription drug orders based on routine, regularly observed prescribing patterns; or

(C) for the purpose of or as an incident to research, teaching, or chemical analysis and not for sale or dispensing.

(11) [~~(10)~~] Confidential record–Any health-related record that contains information that identifies an individual and that is maintained by a pharmacy or pharmacist, such as a patient medication record, prescription drug order, or medication order.

(12) [~~(11)~~] Controlled substance–A drug, immediate precursor, or other substance listed in Schedules I-V or Penalty Groups 1-4 of the Texas Controlled Substances Act, as amended, or a drug, immediate precursor, or other substance included in Schedules I, II, III, IV, or V of the Federal Comprehensive Drug Abuse Prevention and Control Act of 1970, as amended (Public Law 91-513).

(13) [~~(12)~~] Dangerous drug–Any drug or device that is not included in Penalty Groups 1-4 of the Controlled Substances Act and that is unsafe for self-medication or any drug or device that bears or is required to bear the legend:

(A) "Caution: federal law prohibits dispensing without prescription"; or

(B) "Caution: federal law restricts this drug to use by or on the order of a licensed veterinarian."

(14) [~~(13)~~] Data communication device–An electronic device that receives electronic information from one source and transmits or routes it to another (e.g., bridge, router, switch or gateway).

(15) [~~(14)~~] Deliver or delivery–The actual, constructive, or attempted transfer of a prescription drug or device or controlled substance from one person to another, whether or not for a consideration.

(16) [~~(15)~~] Designated agent–

(A) a licensed nurse, physician assistant, pharmacist, or other individual designated by a practitioner to communicate prescription drug orders to a pharmacist;

(B) a licensed nurse, physician assistant, or pharmacist employed in a health care facility to whom the practitioner communicates a prescription drug order; [~~or~~]

(C) an advanced practice nurse or physician assistant authorized by a practitioner to carry out or sign a prescription drug order for dangerous drugs under Chapter 157 of the Medical Practice Act (Subtitle B, Occupations Code); or [~~the Medical Practice Act, §3.06(d)(5) or (6) (Texas Civil Statutes, Article 4495b).~~]

(D) a person who is a licensed vocational nurse or has an education equivalent to or greater than that required for a licensed vocational nurse designated by the practitioner to communicate prescriptions for an advanced practice nurse or physician assistant authorized by the practitioner to sign prescription drug orders under Chapter 157 of the Medical Practice Act (Subtitle B, Occupations Code).

(17) [~~(16)~~] Dispense–Preparing, packaging, compounding, or labeling for delivery a prescription drug or device in the course of professional practice to an ultimate user or his agent by or pursuant to the lawful order of a practitioner.

(18) [~~(17)~~] Dispensing pharmacist–The pharmacist responsible for the final check of the dispensed prescription before delivery to the patient.

(19) [~~(18)~~] Distribute–The delivery of a prescription drug or device other than by administering or dispensing.

(20) [~~(19)~~] Downtime–Period of time during which a data processing system is not operable.

(21) [~~(20)~~] Drug regimen review–An evaluation of prescription drug orders and patient medication records for:

(A) known allergies;

(B) rational therapy-contraindications;

(C) reasonable dose and route of administration;

(D) reasonable directions for use;

(E) duplication of therapy;

(F) drug-drug interactions;

(G) drug-food interactions;

(H) drug-disease interactions;

(I) adverse drug reactions; and

(J) proper utilization, including overutilization or underutilization.

(22) [~~(21)~~] Electronic prescription drug order–A prescription drug order which is transmitted by an electronic device to the receiver (pharmacy).

(23) Electronic signature–A unique security code or other identifier which specifically identifies the person entering information into a data processing system. A facility which utilizes electronic signatures must:

(A) maintain a permanent list of the unique security codes assigned to persons authorized to use the data processing system; and

(B) have an ongoing security program which is capable of identifying misuse and/or unauthorized use of electronic signatures.

(24) [~~(22)~~] Full-time pharmacist–A pharmacist who works in a pharmacy from 30 to 40 hours per week or, if the pharmacy is open less than 60 hours per week, one-half of the time the pharmacy is open.

(25) [~~(23)~~] Hard copy–A physical document that is readable without the use of a special device (i.e., cathode ray tube (CRT), microfiche reader, etc.).

(26) [~~(24)~~] Manufacturing–The production, preparation, propagation, conversion, or processing of a drug or device, either directly or indirectly, by extraction from substances of natural origin or independently by means of chemical or biological synthesis and includes any packaging or repackaging of the substances or labeling or relabeling of the container and the promotion and marketing of such drugs or devices. Manufacturing also includes the preparation and promotion of commercially available products from bulk compounds for resale by pharmacies, practitioners, or other persons but does not include compounding.

(27) [~~(25)~~] Medical Practice Act–The Texas Medical Practice Act, Subtitle B, Occupations Code [~~Texas Civil Statutes, Article 4495b~~], as amended.

(28) [~~(26)~~] Medication order–A written order from a practitioner or a verbal order from a practitioner or his authorized agent for administration of a drug or device.

(29) [~~(27)~~] New prescription drug order–A prescription drug order that:

(A) has not been dispensed to the patient in the same strength and dosage form by this pharmacy within the last year;

(B) is transferred from another pharmacy; and/or

(C) is a discharge prescription drug order. (Note: furlough prescription drug orders are not considered new prescription drug orders.)

(30) [~~(28)~~] Original prescription–The:

(A) original written prescription drug order; or

(B) original verbal or electronic prescription drug order reduced to writing either manually or electronically by the pharmacist.

(31) [~~(29)~~] Part-time pharmacist–A pharmacist who works less than full-time.

(32) [~~(30)~~] Patient counseling–Communication by the pharmacist of information to the patient or patient's agent in order to improve therapy by ensuring proper use of drugs and devices.

(33) [~~(31)~~] Pharmaceutical care–The provision of drug therapy and other pharmaceutical services intended to assist in the cure or prevention of a disease, elimination or reduction of a patient's symptoms, or arresting or slowing of a disease process.

(34) [~~(32)~~] Pharmacist-in-charge–The pharmacist designated on a pharmacy license as the pharmacist who has the authority

or responsibility for a pharmacy's compliance with laws and rules pertaining to the practice of pharmacy.

(35) [~~(33)~~] Pharmacy technician–Those individuals utilized in pharmacies whose responsibility it shall be to provide technical services that do not require professional judgment concerned with the preparation and distribution of drugs under the direct supervision of and responsible to a pharmacist. Pharmacy technician includes certified pharmacy technicians, pharmacy technicians, and pharmacy technician trainees.

(36) [~~(34)~~] Pharmacy technician trainee–A pharmacy technician:

(A) participating in a pharmacy's technician training program; or

(B) a person currently enrolled in a technician training program accredited by the American Society of Health-System Pharmacists provided:

(i) the person is working during times the individual is assigned to a pharmacy as a part of the experiential component of the American Society of Health-System Pharmacists training program;

(ii) the person is under the direct supervision of and responsible to a pharmacist; and

(iii) the supervising pharmacist conducts in-process and final checks.

(37) [~~(35)~~] Physician assistant–A physician assistant recognized by the Texas State Board of Medical Examiners as having the specialized education and training required under Subtitle B, Chapter 157, Occupations Code [~~the Medical Practice Act, §3.06(d)~~], and issued an identification number by the Texas State Board of Medical Examiners.

(38) [~~(36)~~] Practitioner–

(A) a physician, dentist, podiatrist, veterinarian, or other person licensed or registered to prescribe, distribute, administer, or dispense a prescription drug or device in the course of professional practice in this state;

(B) a person licensed by another state in a health field in which, under Texas law, licensees in this state may legally prescribe dangerous drugs or a person practicing in another state and licensed by another state as a physician, dentist, veterinarian, or podiatrist, having a current Federal Drug Enforcement Administration registration number, and who may legally prescribe Schedule II, III, IV, or V controlled substances in such other state; or

(C) a person licensed in the Dominion of Canada or the United Mexican States in a health field in which, under the laws of this state, a licensee may legally prescribe dangerous drugs;

(D) does not include a person licensed under the Texas Pharmacy Act.

(39) [~~(37)~~] Prepackaging–The act of repackaging and relabeling quantities of drug products from a manufacturer's original commercial container into a prescription container for dispensing by a pharmacist to the ultimate consumer.

(40) [~~(38)~~] Prescription drug order–

(A) a written order from a practitioner or a verbal order from a practitioner or his authorized agent to a pharmacist for a drug or device to be dispensed; or

(B) a written order or a verbal order pursuant to Subtitle B, Chapter 157, Occupations Code. [~~the Medical Practice Act, §3.06(d 5) and (6)~~]

(41) [~~(39)~~] Prospective drug use review–A review of the patient's drug therapy and prescription drug order or medication order prior to dispensing or distributing the drug.

(42) State–One of the 50 United States of America, a U.S. territory, or the District of Columbia.

(43) [~~(40)~~] Texas Controlled Substances Act–The Texas Controlled Substances Act, Health and Safety Code, Chapter 481, as amended.

(44) [~~(41)~~] Written protocol–A physician's order, standing medical order, standing delegation order, or other order or protocol as defined by rule of the Texas State Board of Medical Examiners under the Texas Medical Practice Act[~~, (Texas Civil Statutes, Article 4495b)~~].

§291.32. Personnel.

(a) Pharmacist-in-charge.

(1) General.

(A) (No change.)

(B) The pharmacist-in-charge shall comply with the provisions of §291.17 of this title (relating to Inventory Requirements).

(2) Responsibilities. The pharmacist-in-charge shall have responsibility for, at a minimum, the following:

(A)-(L) (No change.)

(M) maintenance of records in a data processing system such that the data processing system is in compliance with Class A (community) pharmacy requirements; [~~and~~]

(N) legal operation of the pharmacy, including meeting all inspection and other requirements of all state and federal laws or sections governing the practice of pharmacy; and

(O) if the pharmacy uses an automated pharmacy dispensing system, shall be responsible for the following:

(i) reviewing and approving all policies and procedures for system operation, safety, security, accuracy and access, patient confidentiality, prevention of unauthorized access, and malfunction;

(ii) inspecting medications in the automated pharmacy dispensing system, at least monthly, for expiration date, misbranding, physical integrity, security, and accountability;

(iii) assigning, discontinuing, or changing personnel access to the automated pharmacy dispensing system;

(iv) ensuring that pharmacy technicians and licensed healthcare professionals performing any services in connection with an automated pharmacy dispensing system have been properly trained on the use of the system and can demonstrate comprehensive knowledge of the written policies and procedures for operation of the system; and

(v) ensuring that the automated pharmacy dispensing system is stocked accurately and an accountability record is maintained in accordance with the written policies and procedures of operation.

(b) Pharmacists.

(1) (No change.)

(2) Duties. Duties which may only be performed by a pharmacist are as follows:

(A)-(H) (No change.)

(I) performing a specific act of drug therapy management for a patient delegated to a pharmacist by a written protocol from a physician licensed in this state in compliance with the Medical Practice Act [~~(Texas Civil Statutes, Article 4495b)~~].

(3) (No change.)

(c) Pharmacy technicians.

(1) (No change.)

(2) Duties.

(A) General.

(i) (No change.)

(ii) A pharmacist may delegate to pharmacy technicians any nonjudgmental technical duty associated with the preparation and distribution of prescription drugs provided:

(I) a pharmacist conducts in-process and final checks; [~~and~~]

(II) pharmacy technicians are under the direct supervision of and responsible to a pharmacist; and

(III) only pharmacy technicians who have been properly trained on the use of an automated pharmacy dispensing system and can demonstrate comprehensive knowledge of the written policies and procedures for the operation of the system may be allowed access to the system.

(B) (No change.)

(3)-(5) (No change.)

(d) (No change.)

§291.33. Operational Standards.

(a) Licensing requirements.

(1) A Class[~~.~~] A pharmacy shall register annually or biennially with the board on a pharmacy license application provided by the board, following the procedures specified in §291.1 of this title (relating to Pharmacy License Application).

(2) A Class[~~.~~] A pharmacy which changes ownership shall notify the board within ten days of the change of ownership and apply for a new and separate license as specified in §291.4 of this title (relating to Change of Ownership).

(3) A Class[~~.~~] A pharmacy which changes location and/or name shall notify the board within ten days of the change and file for an amended license as specified in §291.2 of this title (relating to Change of Location and/or Name).

(4) A Class[~~.~~] A pharmacy owned by a partnership or corporation which changes managing officers shall notify the board in writing of the names of the new managing officers within ten days of the change, following the procedures in §291.3 of this title (relating to Change of Managing Officers).

(5) A Class[~~.~~] A pharmacy shall notify the board in writing within ten days of closing, following the procedures in §291.5 of this title (relating to Closed Pharmacies).

(6) A separate license is required for each principal place of business and only one pharmacy license may be issued to a specific location.

(7) A fee as specified in §291.6 of this title (relating to Pharmacy License Fees) will be charged for the issuance and renewal of a license and the issuance of an amended license.

(8) A Class[~~.~~] A pharmacy, licensed under the provisions of the Act, §560.051(a)(1), [~~§29(b)(1),~~] which also operates another type of pharmacy which would otherwise be required to be licensed under the Act, §560.051(a)(2) [~~§29(b)(2)~~], concerning Nuclear Pharmacy (Class B), is not required to secure a license for such other type of pharmacy; provided, however, such licensee is required to comply with the provisions of §291.51 of this title (relating to Purpose), §291.52 of this title (relating to Definitions), §291.53 of this title (relating to Personnel), §291.54 of this title (relating to Operational Standards), and §291.55 of this title (relating to Records), contained in Nuclear Pharmacy (Class B), to the extent such sections are applicable to the operation of the pharmacy. [~~§291.51 of this title (relating to Definitions), §291.52 of this title (relating to Personnel), §291.53 of this title (relating to Operational Standards), and §291.54 of this title (relating to Records), contained in Nuclear Pharmacy (Class B), to the extent such sections are applicable to the operation of the pharmacy.~~]

(9) A Class[~~.~~] A (community) pharmacy engaged in the compounding of sterile pharmaceuticals shall comply with the provisions of §291.36 of this title (relating to Class A Pharmacies Compounding Sterile Pharmaceuticals).

(b) Environment.

(1) General requirements.

(A) (No change.)

[~~(B) A sink with running water shall be available to all pharmacy personnel and maintained in a sanitary condition.~~]

(B) [~~(C)~~] A Class A pharmacy [~~initially licensed after June 1, 1989,~~] shall have a sink with hot and cold running water within the pharmacy, exclusive of restroom facilities, available to all pharmacy personnel and maintained in a sanitary condition.

(C) [~~(D)~~] A Class A pharmacy which serves the general public shall contain an area which is suitable for confidential patient counseling. [~~A Class A pharmacy initially licensed after June 1, 1989, shall contain an area which is suitable for confidential patient counseling and beginning January 1, 1995, all Class A pharmacies shall contain an area which is suitable for confidential patient counseling.~~]

(i) Such counseling area shall:

(I) be easily accessible to both patient and pharmacists and not allow patient access to prescription drugs;

(II) be designed to maintain the confidentiality and privacy of the pharmacist/patient communication.

(ii) In determining whether the area is suitable for confidential patient counseling and designed to maintain the confidentiality and privacy of the pharmacist/patient communication, the board may consider factors such as the following:

(I) the proximity of the counseling area to the check-out or cash register area;

(II) the volume of pedestrian traffic in and around the counseling area;

(III) the presence of walls or other barriers between the counseling area and other areas of the pharmacy; and

(IV) any evidence of confidential information being overheard by persons other than the patient or patient's agent or the pharmacist or agents of the pharmacist.

(D) [~~(E)~~] The pharmacy shall be properly lighted and ventilated.

(E) [~~(F)~~] The temperature of the pharmacy shall be maintained within a range compatible with the proper storage of drugs; the temperature of the refrigerator shall be maintained within a range compatible with the proper storage of drugs requiring refrigeration.

(F) [~~(G)~~] Animals, including birds and reptiles, shall not be kept within the pharmacy and in immediately adjacent areas under the control of the pharmacy. This provision does not apply to fish in aquariums, guide dogs accompanying disabled persons, or animals for sale to the general public in a separate area that is inspected by local health jurisdictions.

(2)-(3) (No change.)

(c) Prescription dispensing and delivery.

(1) Patient counseling and provision of drug information.

(A) (No change.)

(B) Such communication:

(i)-(iii) (No change.)

(iv) [~~Beginning September 1, 1993,~~] the communication shall be reinforced with written information. The following is applicable concerning this written information.

(I)-(III) (No change.)

(C)-(D) (No change.)

(E) In addition to the requirements of subparagraphs (A)-(D) of this paragraph, if a prescription drug order is delivered to the patient at the pharmacy, the following is applicable.

(i)-(iii) (No change.)

(iv) A Class A pharmacy shall make available for use by the public a current or updated edition of the United States Pharmacopeia Dispensing Information, Volume II (Advice to the Patient), or another source of such information designed for the consumer. [~~, such as patient information leaflets.~~]

(F) In addition to the requirements of subparagraphs (A)-(D) of this paragraph, if a prescription drug order is delivered to the patient or his or her agent at the patient's residence or other designated location, the following is applicable.

(i)-(ii) (No change.)

(iii) The pharmacist shall place on the prescription container or on a separate sheet delivered with the prescription container in both English and Spanish the local and if applicable, toll-free telephone number of the pharmacy and the statement: "Written information about this prescription has been provided for you. Please read this information before you take the medication. If you have questions concerning this prescription, a pharmacist is available during normal business hours to answer these questions at (insert the pharmacy's local and toll-free telephone numbers)."

(iv) The pharmacy shall maintain and use adequate storage or shipment containers and use shipping processes to ensure drug stability and potency. Such shipping processes shall include the use of appropriate packaging material and/or devices to ensure that the drug is maintained at an appropriate temperature range to maintain the integrity of the medication throughout the delivery process.

(v) The pharmacy shall use a delivery system which is designed to assure that the drugs are delivered to the appropriate patient.

(G) (No change.)

(2) Pharmaceutical care services.

(A) Drug regimen review.

(i) For the purpose of promoting therapeutic appropriateness, a pharmacist shall at the time of dispensing a prescription drug order, review the patient's medication record. Such review shall at a minimum identify clinically significant:

(I) known allergies;

(II) rational therapy-contraindications;

(III) reasonable dose and route of administration;

(IV) reasonable directions for use;

(V) duplication of therapy;

(VI) drug-drug interactions;

(VII) drug-food interactions;

(VIII) drug-disease interactions;

(IX) adverse drug reactions; and

(X) proper utilization, including overutilization or underutilization.

[~~*(I)* inappropriate drug utilization;~~]

[~~*(II)* therapeutic duplication;~~]

[~~*(III)* drug-disease contraindications;~~]

[~~*(IV)* drug-drug interactions;~~]

[~~*(V)* incorrect drug dosage or duration of drug treatment;~~]

[~~*(VI)* drug-allergy interactions; and~~]

[~~*(VII)* clinical abuse/misuse.~~]

(ii) Upon identifying any clinically significant conditions, situations, or items listed in clause (i) of this subparagraph, the pharmacist shall take appropriate steps to avoid or resolve the problem including consultation with the prescribing practitioner. The pharmacist shall document such occurrences if the prescription is dispensed. The documentation shall:

(I) be maintained at the pharmacy for two years;

(II) contain the following information:

(-a-) unique prescription number;

(-b-) patient name;

(-c-) date of the review if different from the dispensing date;

(-d-) the name, initials, or identification code of the pharmacist who performed the review; and

(-e-) steps taken to resolve the problem; and

(III) be available in hard copy format, if so requested by an agent of the board.

(B) Other pharmaceutical care services which may be provided by pharmacists include, but are not limited to, the following:

(i) managing drug therapy as delegated by a practitioner as allowed under the provisions of the Medical Practices Act[~~, Texas Civil Statutes, Article 4495b~~];

(ii) administering immunizations and vaccinations under written protocol of a physician;

(iii) [~~(ii)~~] managing patient compliance programs;

(iv) [~~(iii)~~] providing preventative health care services; and

(v) [~~(iv)~~] providing case management of patients who are being treated with high-risk or high-cost drugs, or who are considered "high risk" due to their age, medical condition, family history, or related concern.

(3) Prescription containers.

(A) (No change.)

(B) A drug dispensed pursuant to a prescription drug order shall be dispensed in an appropriate container as specified on the manufacturer's container. [~~follows.~~

~~*(i)* If a drug is susceptible to light, the drug shall be dispensed in a light-resistant container.~~]

[~~*(ii)* If a drug is susceptible to moisture, the drug shall be dispensed in a tight container.~~]

[~~*(iii)* The container should not interact physically or chemically with the drug product placed in it so as to alter the strength, quality, or purity of the drug beyond the official requirements.~~]

(C) (No change.)

(4) Labeling.

(A) At the time of delivery of the drug, the dispensing container shall bear a label with at least the following information:

(i)-(iii) (No change.)

(iv) initials or an identification code of the dispensing pharmacist; [~~name or initials of the dispensing pharmacist;~~]

(v)-(x) (No change.)

(xi) if the pharmacist has selected a generically equivalent drug pursuant to the provisions of the Act, Chapters 562 and 563 [~~§40~~], the statement "Substituted for Brand Prescribed" or "Substituted for 'Brand Name'" where "Brand Name" is the actual name of the brand name product prescribed;

(xii) the name of the advanced practice nurse or physician assistant, if the prescription is carried out or signed by an advanced practice nurse or physician assistant in compliance with Subtitle B, Chapter 157, Occupations Code; [~~the Medical Practice Act, §3.06(d);~~] and

(xiii) (No change.)

(B) (No change.)

(d) Equipment and supplies.

(1) Class A pharmacies dispensing prescription drug orders shall have the following equipment and supplies:

(A)-(B) (No change.)

(C) adequate supply of child-resistant, light-resistant, [~~and~~] tight, and if applicable, glass containers;

(D)-(F) (No change.)

(2) (No change.)

[~~(3) Automated dispensing or compounding devices(s). If automated dispensing or compounded device(s) are used, the pharmacy shall have a method to calibrate and verify the accuracy of the automated dispensing or compounding devices and document the calibration and verification on a routine basis.~~]

(e) Library. A reference library shall be maintained which includes the following in hard-copy or electronic format:

(1) (No change.)

(2) at least one current or updated reference from each of the following categories:

(A)-(B) (No change.)

(C) a general information reference text, such as:

(i)-(iv) (No change.)

(3) (No change.)

(f) (No change.)

(g) Prepackaging of drugs [~~and loading bulk unlabeled drugs into automated drug dispensing system~~].

[~~(1) Prepackaging of drugs.~~]

(1) [~~(A)~~] Drugs may be prepackaged in quantities suitable for internal distribution only by a pharmacist or by supportive personnel under the direction and direct supervision of a pharmacist.

(2) [~~(B)~~] The label of a prepackaged unit shall indicate:

(A) [~~(i)~~] brand name and strength of the drug; or if no brand name, then the generic name, strength, and name of the manufacturer or distributor;

(B) [~~(ii)~~] facility's lot number;

(C) [~~(iii)~~] expiration date; and

(D) [~~(iv)~~] quantity of the drug, if the quantity is greater than one.

(3) [~~(C)~~] Records of prepackaging shall be maintained to show:

(A) [~~(i)~~] name of the drug, strength, and dosage form;

(B) [~~(ii)~~] facility's lot number;

(C) [~~(iii)~~] manufacturer or distributor;

(D) [~~(iv)~~] manufacturer's lot number;

(E) [~~(v)~~] expiration date;

(F) [~~(vi)~~] quantity per prepackaged unit;

(G) [~~(vii)~~] number of prepackaged units;

(H) [~~(viii)~~] date packaged;

(I) [~~(ix)~~] name, initials, or electronic signature [~~name or initials~~] of the prepacker; and

(J) [~~(x)~~] signature, or electronic signature of the responsible pharmacist.

(4) [~~(D)~~] Stock packages, repackaged units, and control records shall be quarantined together until checked/released by the pharmacist.

[~~(2) Loading bulk unlabeled drugs into automated drug dispensing systems.~~]

[~~(A) Automated drug dispensing systems may be loaded with bulk unlabeled drugs only by a pharmacist or by supportive personnel under the direction and direct supervision of a pharmacist.~~]

[~~(B) The label of an automated drug dispensing system container shall indicate the brand name and strength of the drug; or if no brand name, then the generic name, strength, and name of the manufacturer or distributor.~~]

[~~(C) Records of loading bulk unlabeled drugs into an automated drug dispensing system shall be maintained to show:~~]

[~~*(i)* name of the drug, strength, and dosage form;~~]

[~~*(ii)* manufacturer or distributor;~~]

[~~*(iii)* manufacturer's lot number;~~]

[~~*(iv)* expiration date;~~]

[~~*(v)* quantity added to the automated drug dispensing system;~~]

[~~*(vi)* date of loading;~~]

[~~*(vii)* name or initials of the person loading the automated drug dispensing system; and~~]

[~~*(viii)* signature of the responsible pharmacist.~~]

[~~(D) The automated drug dispensing system shall not be used until a pharmacist verifies that the system is properly loaded and affixes his or her signature to the record specified in subparagraph (C) of this paragraph.~~]

(h) Customized patient medication packages.

(1)-(2) (No change.)

(3) Label.

(A) The patient med-pak shall bear a label stating:

(i)-(ix) (No change.)

(x) the initials or an identification code of the dispensing pharmacist; [~~the initials of the dispensing pharmacist;~~] and

(xi) (No change.)

(B)-(C) (No change.)

(4)-(6) (No change.)

(7) Recordkeeping. In addition to any individual prescription filing requirements, a record of each patient med-pak shall be made and filed. Each record shall contain, as a minimum:

(A)-(F) (No change.)

(G) the initials or an identification code of the dispensing pharmacist. [~~the name or initials of the pharmacist who prepared the patient med-pak.~~]

(i) (No change.)

(j) Automated devices and systems.

(1) Automated compounding or counting devices. If a pharmacy uses automated compounded or counting devices:

(A) the pharmacy shall have a method to calibrate and verify the accuracy of the automated compounded or counting device and document the calibration and verification on a routine basis;

(B) the devices may be loaded with bulk or unlabeled drugs only by a pharmacist or by supportive personnel under the direction and direct supervision of a pharmacist;

(C) the label of an automated compounded or counting device container shall indicate the brand name and strength of the drug; or if no brand name, then the generic name, strength, and name of the manufacturer or distributor;

(D) records of loading bulk or unlabeled drugs into an automated compounding or counting device shall be maintained to show:

(i) name of the drug, strength, and dosage form;

(ii) manufacturer or distributor;

(iii) manufacturer's lot number;

(iv) expiration date;

(v) quantity added to the automated compounded or counting device;

(vi) date of loading;

(vii) name, initials, or electronic signature of the person loading the automated compounding or counting device; and

(viii) signature or electronic signature of the responsible pharmacist; and

(E) the automated compounded or counting device shall not be used until a pharmacist verifies that the system is properly loaded and affixes his or her signature to the record specified in subparagraph (D) of this paragraph.

(2) Automated pharmacy dispensing systems.

(A) Authority to use automated pharmacy dispensing systems. A pharmacy may use an automated pharmacy dispensing system to fill prescription drug orders provided that:

(i) the pharmacist-in-charge is responsible for the supervision of the operation of the system;

(ii) the automated pharmacy dispensing system has been tested by the pharmacy and found to dispense accurately. The pharmacy shall make the results of such testing available to the Board upon request; and

(iii) the pharmacy will make the automated pharmacy dispensing system available for inspection by the board for the purpose of validating the accuracy of the system.

(B) Quality assurance program. A pharmacy which uses an automated pharmacy dispensing system to fill prescription drug orders shall operate according to a written program for quality assurance of the automated pharmacy dispensing system which:

(i) requires continuous monitoring of the automated pharmacy dispensing system; and

(ii) establishes mechanisms and procedures to test the accuracy of the automated pharmacy dispensing system at least every six months and whenever any upgrade or change is made to the system and documents each such activity.

(C) Policies and procedures of operation.

(i) When an automated pharmacy dispensing system is used to fill prescription drug orders, it shall be operated according to written policies and procedures of operation. The policies and procedures of operation shall establish requirements for operation of the automated pharmacy dispensing system and shall describe policies and procedures that:

(I) include a description of the policies and procedures of operation;

(II) ensure that a pharmacist reviews, approves, and is held accountable for the transmission of each original or new prescription drug order to the automated pharmacy dispensing system before the transmission is made;

(III) ensure access to the automated pharmacy dispensing system for stocking and retrieval of medications is limited to licensed healthcare professionals or pharmacy technicians acting under the supervision of a pharmacist;

(IV) provide for and ensure that prior to use, a pharmacist checks, verifies, and documents that the automated pharmacy dispensing system has been accurately filled each time the system is stocked;

(V) provide for an accountability record to be maintained which documents all transactions relative to stocking and removing medications from the automated pharmacy dispensing system;

(VI) ensure a prospective drug regimen review is conducted as specified in subsection (c)(2) of this section; and

(VII) establish and make provisions for documentation of a preventative maintenance program for the automated pharmacy dispensing system.

(ii) A pharmacy which uses an automated pharmacy dispensing system to fill prescription drug orders shall, at least annually, review its written policies and procedures, revise them if necessary, and document the review.

(D) Recovery Plan. A pharmacy which uses an automated pharmacy dispensing system to fill prescription drug orders shall maintain a written plan for recovery from a disaster or any other situation which interrupts the ability of the automated pharmacy dispensing system to provide services necessary for the operation of the pharmacy. The written plan for recovery shall include:

(i) planning and preparation for maintaining pharmacy services when an automated pharmacy dispensing system is experiencing downtime;

(ii) procedures for response when an automated pharmacy dispensing system is experiencing downtime;

(iii) procedures for the maintenance and testing of the written plan for recovery; and

(iv) procedures for notification of the Board, each patient of the pharmacy, and other appropriate agencies whenever an automated pharmacy dispensing system experiences downtime for more than two days of operation or a period of time which significantly limits the pharmacy's ability to provide pharmacy services.

§291.34. Records.

(a) (No change.)

(b) Prescriptions.

(1) (No change.)

(2) Written prescription drug orders.

(A) Practitioner's [~~Practioner's~~] signature. Written prescription drug orders shall be manually signed by the practitioner [~~practioner~~] (electronically produced or rubber stamped signatures may not be used).

(i) A practitioner [~~practioner~~] may sign a prescription drug order in the same manner as he would sign a check or legal document, e.g. J.H. Smith or John H. Smith.

(ii) The prescription drug order may not be signed by a practitioner's [~~practioner's~~] agent but may be prepared by an agent for the signature of a practitioner [~~practioner~~]. However, the prescribing practitioner [~~practioner~~] is responsible in case the prescription drug order does not conform in all essential respects to the law and regulations.

(B) Required prescription drug order format.

(i) (No change.)

(ii) The two signature line requirement does not apply to the following types of prescription drug orders:

(I) prescription drug orders issued by a practitioner [~~practioner~~] in a state other than Texas;

(II) prescription drug orders for dangerous drugs issued by a practitioner [~~practioner~~] in the United Mexican States or the Dominion of Canada; and

(III) prescription drug orders issued by a practitioner [~~practioners~~] practicing in a federal facility provided they are acting in the scope of their employment.

(C) Preprinted prescription drug order forms. No prescription drug order form furnished to a practitioner [~~practioner~~] shall contain a preprinted order for a drug product by brand name, generic name, or manufacturer.

(D) Prescription drug orders written by practitioners [~~practioners~~] in another state.

(i) Dangerous drug prescription orders. A pharmacist may dispense a prescription drug order for dangerous drugs issued by practitioners [~~practioners~~] in a state other than Texas in the same manner as prescription drug orders for dangerous drugs issued by practitioners [~~practioners~~] in Texas are dispensed.

(ii) Controlled substance prescription drug orders.

(I) A pharmacist may dispense prescription drug order for controlled substances in Schedule II issued by a practitioner in another state provided:

(-a-) the prescription is filled in compliance with a written plan approved by the Director of the Texas Department of Public Safety in consultation with the Board, which provides the manner in which the dispensing pharmacy may fill a prescription for a Schedule II controlled substance;

(-b-) the prescription drug order is an original written prescription issued by a person practicing in another state and licensed by another state as a physician, dentist, veterinarian, or podiatrist, who has a current federal Drug Enforcement Administration (DEA) registration number, and who may legally prescribe Schedule II controlled substances in such other state; and

(-c-) the prescription drug order is not dispensed more than six months from the initial date of issuance and may not be refilled.

(II) A pharmacist may dispense prescription drug orders for controlled substances in Schedule III, IV, or V issued by a practitioner [~~practioner~~] in another state provided:

(-a-) [~~(I)~~] the prescription drug order is an original written prescription issued by a person practicing in another state and licensed by another state as a physician, dentist, veterinarian, or podiatrist, who has a current federal Drug Enforcement Administration (DEA) registration number, and who may legally prescribe Schedule III, IV, or V controlled substances in such other state;

(-b-) [~~(II)~~] the prescription drug order is not dispensed or refilled more than six months from the initial date of issuance and may not be refilled more than five times; and

(-c-) [~~(III)~~] if there are no refill instructions on the original written prescription drug order (which shall be interpreted as no refills authorized) or if all refills authorized on the original written prescription drug order have been dispensed, a new written prescription drug order is obtained from the prescribing practitioner [~~practioner~~] prior to dispensing any additional quantities of controlled substances.

(E) prescription drug orders written by practitioners [~~practioners~~] in the United Mexican States or the Dominion of Canada.

(i) Controlled substance prescription drug orders. A pharmacist may not dispense a prescription drug order for a Schedule II, III, IV, or V controlled substance issued by a practitioner [~~practioner~~] in the Dominion of Canada or the United Mexican States.

(ii) Dangerous drug prescription drug orders. A pharmacist may dispense a dangerous drug prescription issued by a person licensed in the Dominion of Canada or the United Mexican States as a physician, dentist, veterinarian, or podiatrist provided:

(I) (No change.)

(II) if there are no refill instructions on the original written prescription drug order (which shall be interpreted as no refills authorized) or if all refills authorized on the original written prescription drug order have been dispensed, a new written prescription drug order shall be obtained from the prescribing practitioner [~~practioner~~] prior to dispensing any additional quantities of dangerous drugs.

(F) Prescription drug orders carried out or signed by an advanced practice nurse or physician assistant.

(i) A pharmacist may dispense a prescription drug order for a dangerous drug which is carried out or signed by an advanced practice nurse or physician assistant provided:

(I) (No change.)

(II) the advanced practice nurse or physician assistant is practicing in accordance with Subtitle B, Chapter 157, Occupations Code. [~~the Medical Practice Act, §3.06(d).~~]

(ii) Each practitioner shall designate in writing the name of each advanced practice nurse or physician assistant authorized to carry out or sign a prescription drug order pursuant to Subtitle B, Chapter 157, Occupations Code. [~~the Medical Practice Act, §3.06(d).~~] A list of the advanced practice nurses or physician assistants designated by the practitioner must be maintained in the practitioner's usual place of business. On request by a pharmacist, a practitioner shall furnish the pharmacist with a copy of the written authorization for a specific advanced practice nurse or physician assistant.

(G) Prescription drug orders for Schedule II controlled substances. No Schedule II controlled substance may be dispensed without a written prescription drug order of a practitioner on an official [~~a triplicate~~] prescription form as required by the Texas Controlled Substances Act, §481.075.

(3)-(5) (No change.)

(6) Therapeutic Drug Interchange. A switch to a drug providing a similar therapeutic response to the one prescribed shall not be made without prior approval of the prescribing practitioner.

(A) The patient shall be notified of the therapeutic drug interchange prior to, or upon delivery, of the dispensed prescription to the patient. Such notification shall include:

(i) a description of the change;

(ii) the reason for the change;

(iii) whom to notify with questions concerning the change; and

(iv) instructions for return of the drug if not wanted by the patient.

(B) The pharmacy shall maintain documentation of patient notification of therapeutic drug interchange which shall include:

(i) the date of the notification;

(ii) the method of notification;

(iii) a description of the change; and

(iv) the reason for the change.

(7) [~~(6)~~] Original prescription drug order records.

(A) Original prescriptions shall be maintained by the pharmacy in numerical order and remain legible for a period of two years from the date of filling or the date of the last refill dispensed.

(B) If an original prescription drug order is changed, such prescription order shall be invalid and of no further force and effect; if additional drugs are to be dispensed, a new prescription drug order with a new and separate number is required.

(C) Original prescriptions shall be maintained in three separate files as follows:

(i) prescriptions for controlled substances listed in Schedule II;

(ii) prescriptions for controlled substances listed in Schedule III-V; and

(iii) prescriptions for dangerous drugs and nonprescription drugs.

(D) Original prescription records other than prescriptions for Schedule II controlled substances [~~triplicate prescriptions~~] may be stored on microfilm, microfiche, or other system which is capable of producing a direct image of the original prescription record, e.g., digitalized imaging system. If original prescription records are stored in a direct imaging system, the following is applicable:

(i) the record of refills recorded on the original prescription must also be stored in this system;

(ii) the original prescription records must be maintained in numerical order and separated in three files as specified in subparagraph (C) of this paragraph; and

(iii) the pharmacy must provide immediate access to equipment necessary to render the records easily readable.

<u>(8)</u> [~~(7)~~] Prescription drug order information.

(A) All original prescriptions shall bear:

(i) name of the patient, or if such drug is for an animal, the species of such animal and the name of the owner;

(ii) address of the patient, provided, however, a prescription for a dangerous drug is not required to bear the address of the patient if such address is readily retrievable on another appropriate, uniformly maintained pharmacy record, such as medication records;

(iii) name, and if for a controlled substance, the address and DEA registration number of the practitioner;

(iv) name and strength of the drug prescribed;

(v) quantity prescribed;

(vi) directions for use;

(vii) intended use for the drug unless the practitioner determines the furnishing of this information is not in the best interest of the patient; and

(viii) date of issuance.

(B) All original electronic prescription drug orders shall bear:

(i) name of the patient, if such drug is for an animal, the species of such animal, and the name of the owner;

(ii) address of the patient, provided, however, a prescription for a dangerous drug is not required to bear the address of the patient if such address is readily retrievable on another appropriate, uniformly maintained pharmacy record, such as medication records;

(iii) name, and if for a controlled substance, the address and DEA registration number of the practitioner;

(iv) name and strength of the drug prescribed;

(v) quantity prescribed;

(vi) directions for use;

(vii) indications for use, unless the practitioner determines the furnishing of this information is not in the best interest of the patient;

(viii) date of issuance;

(ix) a statement which indicates that the prescription has been electronically transmitted, (e.g., Faxed to or electronically transmitted to:);

(x) name, address, and electronic access number of the pharmacy to which the prescription was transmitted;

(xi) telephone number of the prescribing practitioner;

(xii) date the prescription drug order was electronically transmitted to the pharmacy, if different from the date of issuance of the prescription; and

(xiii) if transmitted by a designated agent, the full name of the designated agent.

(C) All original written prescriptions for dangerous drugs carried out or signed by an advanced practice nurse or physician assistant in accordance with <u>Subtitle B, Chapter 157, Occupations Code</u> [~~the Medical Practice Act, §3.06(d)~~], shall bear:

(i) name and address of the patient;

(ii) name, address, <u>and</u> telephone number[~~, and original signature~~] of the <u>supervising</u> practitioner;

(iii) name, identification number, and original signature of the advanced practice nurse or physician assistant;

(iv) address and telephone number of the clinic at which the prescription drug order was carried out or signed;

(v) name, strength, and quantity of the dangerous drug;

(vi) directions for use;

(vii) indications for use, if appropriate;

(viii) date of issuance; and

(ix) number of refills authorized.

(D) At the time of dispensing, a pharmacist is responsible for the addition of the following information to the original prescription:

(i) unique identification number of the prescription drug order;

(ii) initials or identification code of the dispensing pharmacist;

(iii) quantity dispensed, if different from the quantity prescribed;

(iv) date of dispensing, if different from the date of issuance; and

(v) brand name or manufacturer of the drug product actually dispensed, if the drug was prescribed by generic name or if a drug product other than the one prescribed was dispensed pursuant to the provisions of the Act, <u>Chapters 562 and 563</u> [~~§40~~].

<u>(9)</u> [~~(8)~~] Refills.

(A) Refills may be dispensed only in accordance with the prescriber's authorization as indicated on the original prescription drug order.

(B) If there are no refill instructions on the original prescription drug order (which shall be interpreted as no refills authorized) or if all refills authorized on the original prescription drug order have been dispensed, authorization from the prescribing practitioner shall be obtained prior to dispensing any refills.

(C) Refills of prescription drug orders for dangerous drugs or nonprescription drugs.

(i) Prescription drug orders for dangerous drugs or nonprescription drugs may not be refilled after one year from the date of issuance of the original prescription drug order.

(ii) If one year has expired from the date of issuance of an original prescription drug order for a dangerous drug or nonprescription drug, authorization shall be obtained from the prescribing practitioner prior to dispensing any additional quantities of the drug.

(D) Refills of prescription drug orders for Schedule III-V controlled substances.

(i) Prescription drug orders for Schedule III-V controlled substances may not be refilled more than five times or after six months from the date of issuance of the original prescription drug order, whichever occurs first.

(ii) If a prescription drug order for a Schedule III, IV, or V controlled substance has been refilled a total of five times or if six months have expired from the date of issuance of the original prescription drug order, whichever occurs first, a new and separate prescription drug order shall be obtained from the prescribing practitioner prior to dispensing any additional quantities of controlled substances.

(E) A pharmacist may exercise his professional judgment in refilling a prescription drug order for a drug, other than a controlled substance listed in Schedule II, without the authorization of the prescribing practitioner, provided:

(i) failure to refill the prescription might result in an interruption of a therapeutic regimen or create patient suffering;

(ii) either:

(I) a natural or manmade disaster has occurred which prohibits the pharmacist from being able to contact the practitioner; or

(II) the pharmacist is unable to contact the practitioner after a reasonable effort;

(iii) the quantity of prescription drug dispensed does not exceed a 72-hour supply;

(iv) the pharmacist informs the patient or the patient's agent at the time of dispensing that the refill is being provided without such authorization and that authorization of the practitioner is required for future refills;

(v) the pharmacist informs the practitioner of the emergency refill at the earliest reasonable time;

(vi) the pharmacist maintains a record of the emergency refill containing the information required to be maintained on a prescription as specified in this subsection;

(vii) the pharmacist affixes a label to the dispensing container as specified in §291.33(c)(4) of this title (relating to Operational Standards); and

(viii) if the prescription was initially filled at another pharmacy, the pharmacist may exercise his professional judgment in refilling the prescription provided:

(I) the patient has the prescription container, label, receipt or other documentation from the other pharmacy which contains the essential information;

(II) after a reasonable effort, the pharmacist is unable to contact the other pharmacy to transfer the remaining prescription refills or there are no refills remaining on the prescription;

(III) the pharmacist, in his professional judgment, determines that such a request for an emergency refill is appropriate and meets the requirements of clauses (i) and (ii) of this subparagraph; and

(IV) the pharmacist complies with the requirements of clauses (iii)-(v) of this subparagraph.

(c) Patient medication records.

(1) (No change.)

(2) The patient medication record system shall provide for the immediate retrieval of information for the previous 12 months which is necessary for the dispensing pharmacist to conduct a prospective drug regimen [~~use~~] review at the time a prescription drug order is presented for dispensing.

(3) The pharmacist-in-charge shall assure that a reasonable effort is made to obtain and record in the patient medication record at least the following information:

(A)-(D) (No change.)

(E) any known allergies, drug reactions, idiosyncrasies, and chronic conditions or disease states of the patient and the identity of any other drugs currently being used by the patient which may relate to prospective drug regimen [~~use~~] review;

(F)-(G) (No change.)

(4)-(5) (No change.)

(d) (No change.)

(e) Prescription drug order records maintained in a data processing system.

(1)-(3) (No change.)

(4) Transfer of prescription drug order information. For the purpose of refill or initial dispensing, the transfer of original prescription drug order information is permissible between pharmacies, subject to the following requirements.

(A) The transfer of original prescription drug order information for controlled substances listed in Schedules III, IV, or V is permissible between pharmacies on a one-time basis only. However, pharmacies electronically sharing a real-time, on-line database may transfer up to the maximum refills permitted by law and the prescriber's authorization.

(B)-(J) (No change.)

(5) Electronic transfer of prescription drug order information between pharmacies. Pharmacies electronically accessing the same prescription drug order records may electronically transfer prescription information if the following requirements are met.

(A) The original prescription is voided and the following information is documented in the records of the transferring pharmacy: [~~The data processing system shall have a mechanism to send a message to the transferring pharmacy containing the following information:~~]

(i) the name, address, and if a controlled substance, the DEA registration number of the pharmacy to which such prescription is transferred;

(ii) the name of the pharmacist or pharmacist intern receiving the prescription drug order information; and

(iii) the date of the transfer.

[~~*(i)* the fact that the prescription drug order was transferred;~~]

[~~*(ii)* the unique identification number of the prescription drug order transferred;~~]

[~~*(iii)* the name of the pharmacy to which it was transferred; and~~]

[~~*(iv)* the date and time of the transfer.~~]

~~[(B) A pharmacist in the transferring pharmacy shall review the message and document the review by signing and dating a hard copy of the message or a log book containing the information required on the message as soon as practical, but in no event more than 72 hours from the time of such transfer.]~~

(B) [~~(C)~~] Pharmacies not owned by the same person may electronically access the same prescription drug order records, provided the owner or chief executive officer of each pharmacy signs an agreement allowing access to such prescription drug order records.

(6) (No change.)

(f)-(h) (No change.)

(i) Permission to maintain central records. Any pharmacy that uses a centralized recordkeeping system for invoices and financial data shall comply with the following procedures.

(1) Controlled substance records. Invoices and financial data for controlled substances may be maintained at a central location provided the following conditions are met.

(A) Prior to the initiation of central recordkeeping, the pharmacy submits written notification by registered or certified mail to the divisional director of the Drug Enforcement Administration as required by Title 21, Code of Federal Regulations, §1304.04(a) [~~§1304(a)~~], and submits a copy of this written notification to the Texas State Board of Pharmacy. Unless the registrant is informed by the divisional director of the Drug Enforcement Administration that permission to keep central records is denied, the pharmacy may maintain central records commencing 14 days after receipt of notification by the divisional director.

(B)-(C) (No change.)

(2)-(4) (No change.)

(j) (No change.)

(k) Confidentiality.

(1) (No change.)

(2) Confidential records are privileged and may be released only to:

(A) (No change.)

(B) a practitioner or another pharmacist if, in the pharmacist's professional judgement, the release is necessary to protect the patient's health and well being;

(C) the board or to a person or another state or federal agency authorized by law to receive the confidential record;

(D) a law enforcement agency engaged in investigation of a suspected violation of Chapter 481 or 483, Health and Safety Code, or the Comprehensive Drug Abuse Prevention and Control Act of 1970 (21 U.S.C. Section 801 et seq.);

(E) a person employed by a state agency that licenses a practitioner, if the person is performing the person's official duties; or

~~[(B) practitioners and other pharmacists when, in the pharmacist's professional judgment, such release is necessary to protect the patient's health and well-being;]~~

~~[(C) other persons, the board, or other state or federal agencies authorized by law to receive such information;]~~

~~[(D) a law enforcement agency engaged in investigation of suspected violations of the Controlled Substances Act or the Dangerous Drug Act;]~~

~~[(E) a person employed by any state agency which licenses a practitioner as defined in the Act if such person is engaged in the performance of the person's official duties; or]~~

(F) (No change.)

§291.36. Class A Pharmacies Compounding Sterile Pharmaceuticals.

(a) (No change.)

(b) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1)-(7) (No change.)

(8) Automated compounding or counting device [~~Automated compounding or drug dispensing system~~]–An automated device that compounds, measures, counts, and/or packages[~~, and/or labels~~] a specified quantity of dosage units for a designated drug product.

(9)-(58) (No change.)

(c) (No change.)

(d) Operational standards.

(1) Licensing requirements.

(A) A Class A pharmacy compounding sterile pharmaceuticals shall register annually or biennially with the board on a pharmacy license application provided by the board, following the procedures specified in §291.1 of this title (relating to Pharmacy License Application).

(B)-(I) (No change.)

(2) Environment.

(A) (No change.)

(B) Special requirements for the compounding of sterile pharmaceuticals. When the pharmacy compounds sterile pharmaceuticals, the following is applicable.

(i)-(iii) (No change.)

(iv) Automated compounding or counting device [~~Automated compounding device(s)~~]. If automated compounding or counting devices [~~automated compounding device(s)~~] are used, the pharmacy shall have a method to calibrate and verify the accuracy of automated compounding or counting devices [~~automated compounding devices~~] used in aseptic processing and document the calibration and verification on a routine basis.

(v) (No change.)

(C) (No change.)

(3) Prescription dispensing and delivery.

(A) Patient counseling and provision of drug information.

(i)-(v) (No change.)

(vi) In addition to the requirements of clauses (i)-(iv) of this subparagraph, if a prescription drug order is delivered to the patient or his or her agent at the patient's residence or other designated location, the following is applicable.

(I)-(II) (No change.)

(III) The pharmacist shall place on the prescription container or on a separate sheet delivered with the prescription container in both English and Spanish the local and if applicable, toll-free telephone number of the pharmacy and the statement: "Written information about this prescription has been provided for you. Please read this information before you take the medication. If you have questions concerning this prescription, a pharmacist is available during normal business hours to answer these questions at (insert the pharmacy's local and toll-free telephone numbers)."

(IV) The pharmacist-in-charge shall assure that:

(-a-) the pharmacy maintain and use adequate storage or shipment containers and shipping processes [~~are used~~] to ensure drug stability and potency. Such shipping processes shall include the use of appropriate packaging material and/or devices to ensure that the drug is maintained at an appropriate temperature range to maintain the integrity of the medication throughout the delivery process; and

(-b-) the pharmacy uses [~~utilizes~~] a delivery system which is designed to assure that the drugs are delivered to the appropriate patient.

(vii) (No change.)

(B)-(C) (No change.)

(4) Pharmaceutical care services.

(A) The following pharmaceutical care services shall be provided by pharmacists of the pharmacy.

(i) (No change.)

(ii) Drug regimen review.

(I) (No change.)

(II) Upon identifying any clinically significant conditions, situations, or items listed in subclause (I) of this clause, the pharmacist shall take appropriate steps to avoid or resolve the problem including consultation with the prescribing practitioner. The pharmacist shall document such occurrences if the prescription is dispensed. The documentation shall:

(-a-) be maintained at the pharmacy for two years;

(-b-) contain the following information:

(-1-) unique prescription number;

(-2-) patient name;

(-3-) date of the review if different from the dispensing date;

(-4-) the name, initials, or identification code of the pharmacist who performed the review; and

(-5-) steps taken to resolve the problem; and

(-c-) be available in hard copy format, if so requested by an agent of them board.

(iii) (No change.)

(B) (No change.)

(5)-(7) (No change.)

(8) Prepackaging of drugs and loading bulk drugs into automated compounding or counting devices [~~automated compounding or drug dispensing systems~~].

(A) (No change.)

(B) Loading bulk drugs into automated compounding or counting devices [~~automated compounding or drug dispensing systems~~].

(i) Automated compounding or counting devices [~~Automated compounding or drug dispensing systems~~] may be loaded with bulk drugs only by a pharmacist or by pharmacy technicians under the direction and direct supervision of a pharmacist.

(ii) The label of an automated compounding or counting device [~~automated compounding or drug dispensing system~~] container shall indicate the brand name and strength of the drug; or if no brand name, then the generic name, strength, and name of the manufacturer or distributor.

(iii) Records of loading bulk drugs into an automated compounding or counting device [~~automated compounding or drug dispensing system~~] shall be maintained to show:

(I)-(IV) (No change.)

(V) quantity added to the automated compounding or counting device [~~automated compounding or drug dispensing system~~];

(VI) (No change.)

(VII) name, initials, or electronic signature of the person loading the automated compounding or counting device [~~automated compounding or drug dispensing system~~]; and

(VIII) (No change.)

(iv) The automated compounding or counting device [~~automated compounding or drug dispensing system~~] shall not be used until a pharmacist verifies that the system is properly loaded and affixes his or her signature or electronic signature to the record specified in clause (iii) of this subparagraph.

(9) Sterile pharmaceuticals.

(A) Batch preparation.

(i) Master work sheet. A master work sheet shall be developed and approved by a pharmacist for each batch of sterile pharmaceuticals to be prepared. Once approved, a duplicate of the master work sheet shall be used as the preparation work sheet from which each batch is prepared and on which all documentation for that batch occurs. The master work sheet shall contain at a minimum:

(I)-(VI) (No change.)

(VII) specific equipment used during aseptic preparation (e.g., specific automated compounding or counting device [~~automated compounding device~~]); and

(VIII) (No change.)

(ii)-(iii) (No change.)

(B)-(D) (No change.)

(e) Records.

(1) (No change.)

(2) Prescriptions.

(A)-(F) (No change.)

(G) Therapeutic Drug Interchange. A switch to a drug providing a similar therapeutic response to the one prescribed shall not be made without prior approval of the prescribing practitioner.

(i) The patient shall be notified of the therapeutic drug interchange prior to, or upon delivery, of the dispensed prescription to the patient. Such notification shall include:

(I) a description of the change;

(II) the reason for the change;

(III) whom to notify with questions concerning the change; and

(IV) instructions for return of the drug if not wanted by the patient.

(ii) The pharmacy shall maintain documentation of patient notification of therapeutic drug interchange which shall include:

(I) the date of the notification;

(II) the method of notification;

(III) a description of the change; and

(IV) the reason for the change.

(H) [~~(G)~~] Original prescription drug order records.

(i) Original prescriptions shall be maintained by the pharmacy in numerical order and remain legible for a period of two years from the date of filling or the date of the last refill dispensed.

(ii) If an original prescription drug order is changed, such prescription order shall be invalid and of no further force and effect; if additional drugs are to be dispensed, a new prescription drug order with a new and separate number is required.

(iii) Original prescriptions shall be maintained in one of the following formats:

(I) in three separate files as follows:

(-a-) prescriptions for controlled substances listed in Schedule II;

(-b-) prescriptions for controlled substances listed in Schedule III-V; and

(-c-) prescriptions for dangerous drugs and nonprescription drugs; or

(II) within a patient medication record system provided that original prescriptions for controlled substances are maintained separate from original prescriptions for noncontrolled substances and triplicate prescriptions for Schedule II controlled substances are maintained separate from all other original prescriptions.

(iv) Original prescription records other than triplicate prescriptions may be stored on microfilm, microfiche, or other system which is capable of producing a direct image of the original prescription record, e.g., digitalized imaging system. If original prescription records are stored in a direct imaging system, the following is applicable.

(I) The record of refills recorded on the original prescription must also be stored in this system.

(II) The original prescription records must be maintained in numerical order and as specified in clause (iii) of this subparagraph.

(III) The pharmacy must provide immediate access to equipment necessary to render the records easily readable.

(I) [~~(H)~~] Prescription drug order information.

(i) All original prescriptions shall bear:

(I) name of the patient;

(II) address of the patient, provided, however, a prescription for a dangerous drug is not required to bear the address of the patient if such address is readily retrievable on another appropriate, uniformly maintained pharmacy record, such as medication records;

(III) name, and if for a controlled substance, the address and DEA registration number of the practitioner;

(IV) name and strength of the drug prescribed;

(V) quantity prescribed;

(VI) directions for use;

(VII) intended use for the drug unless the practitioner determines the furnishing of this information is not in the best interest of the patient;

(VIII) date of issuance; and

(IX) if telephoned to the pharmacist by a designated agent, the full name of the designated agent.

(ii) All original prescriptions for dangerous drugs carried out by an advanced practice nurse or physician assistant in accordance with the Medical Practice Act, §3.06(d), shall bear:

(I) name and address of the patient;

(II) name, address, telephone number, and original signature of the practitioner;

(III) name, address, telephone number, identification number, and original signature of the advanced practice nurse or physician assistant;

(IV) name, strength, and quantity of the dangerous drug;

(V) directions for use;

(VI) the intended use of the drug, if appropriate;

(VII) date of issuance; and

(VIII) number of refills authorized.

(iii) All original electronic prescription drug orders shall bear:

(I) name of the patient;

(II) address of the patient, provided, however, a prescription for a dangerous drug is not required to bear the address of the patient if such address is readily retrievable on another appropriate, uniformly maintained pharmacy record, such as patient medication records;

(III) name and strength of the drug prescribed;

(IV) quantity prescribed;

(V) directions for use;

(VI) intended use for the drug unless the practitioner determines the furnishing of this information is not in the best interest of the patient;

(VII) date of issuance;

(VIII) a statement which indicates that the prescription has been electronically transmitted (e.g., Faxed to or electronically transmitted to:);

(IX) name, address, and electronic access number of the pharmacy to which the prescription was transmitted;

(X) telephone number of the prescribing practitioner;

(XI) date the prescription drug order was electronically transmitted to the pharmacy, if different from the date of issuance of the prescription; and

(XII) if transmitted by a designated agent, the full name of the designated agent.

(iv) At the time of dispensing, a pharmacist is responsible for the addition of the following information to the original prescription:

(I) unique identification number of the prescription drug order;

(II) initials or identification code of the person who compounded the sterile pharmaceutical and the pharmacist who checked and released the product;

(III) name, quantity, lot number, and expiration date of each product used in compounding the sterile pharmaceutical; and

(IV) date of dispensing, if different from the date of issuance.

(J) [~~(I)~~] Refills.

(i) Refills may be dispensed only in accordance with the prescriber's authorization as indicated on the original prescription drug order. Such refills may be indicated as authorization to refill the prescription drug order a specified number of times or for a specified period of time period, such as the duration of therapy.

(ii) If there are no refill instructions on the original prescription drug order (which shall be interpreted as no refills authorized) or if all refills authorized on the original prescription drug order have been dispensed, authorization from the prescribing practitioner shall be obtained prior to dispensing any refills.

(iii) Refills of prescription drug orders for dangerous drugs or nonprescription drugs shall be dispensed as follows.

(I) Prescription drug orders for dangerous drugs or nonprescription drugs may not be refilled after one year from the date of issuance of the original prescription order.

(II) If one year has expired from the date of issuance of an original prescription drug order for a dangerous drug or nonprescription drug, authorization shall be obtained from the prescribing practitioner prior to dispensing any additional quantities of the drug.

(iv) Refills of prescription drug orders for Schedule III-V controlled substances shall be dispensed as follows.

(I) Prescription drug orders for Schedule III-V controlled substances may not be refilled more than five times or after six months from the date of issuance of the original prescription drug order, whichever occurs first.

(II) If a prescription drug order for a Schedule III, IV, or V controlled substance has been refilled a total of five times or if six months have expired from the date of issuance of the original prescription drug order, whichever comes first, a new and separate prescription drug order shall be obtained from the prescribing practitioner prior to dispensing any additional quantities of controlled substances.

(v) A pharmacist may exercise his professional judgment in refilling a prescription drug order for a drug, other than a controlled substance listed in Schedule II, without the authorization of the prescribing practitioner, provided:

(I) failure to refill the prescription might result in an interruption of a therapeutic regimen or create patient suffering;

(II) either:

(-a-) a natural or manmade disaster has occurred which prohibits the pharmacist from being able to contact the practitioner; or

(-b-) the pharmacist is unable to contact the practitioner after a reasonable effort;

(III) the quantity of prescription drug dispensed does not exceed a 72-hour supply;

(IV) the pharmacist informs the patient or the patient's agent at the time of dispensing that the refill is being provided without such authorization and that authorization of the practitioner is required for future refills;

(V) the pharmacist informs the practitioner of the emergency refill at the earliest reasonable time;

(VI) the pharmacist maintains a record of the emergency refill containing the information required to be maintained on a prescription as specified in this paragraph;

(VII) the pharmacist affixes a label to the dispensing container as specified in this paragraph; and

(VIII) if the prescription was initially filled at another pharmacy, the pharmacist may exercise his professional judgment in refilling the prescription provided:

(-a-) the patient has the prescription container, label, receipt or other documentation from the other pharmacy which contains the essential information;

(-b-) after a reasonable effort, the pharmacist is unable to contact the other pharmacy to transfer the remaining prescription refills or there are no refills remaining on the prescription;

(-c-) the pharmacist, in his professional judgment, determines that such a request for an emergency refill is appropriate and meets the requirements of subclauses (I) and (II) of this clause; and

(IX) the pharmacist complies with the requirements of subclauses (III)-(V) of this clause.

(3)-(11) (No change.)

(f) Triplicate prescription requirements. The Texas State Board of Pharmacy adopts by reference the rules promulgated by the Texas Department of Public Safety, which are set forth in Subchapter F of 37 TAC §§13.101-13.113 concerning triplicate prescriptions.

[~~(1) Definitions. The following words and terms, when used in this subsection, shall have the following meanings, unless the context clearly indicates otherwise.~~]

[~~(A) Designated agent or authorized agent–An individual under the supervision of a practitioner, designated in writing by the practitioner, and for whom the practitioner assumes responsibility, who communicates the practitioner's instructions to the pharmacist. The written designation of an agent authorized to communicate prescriptions shall be maintained in the usual place of business of the practitioner and shall be available for inspection by investigators for~~

~~the Texas State Board of Medical Examiners, the State Board of Dental Examiners, the State Board of Veterinary Medical Examiners, or the Department of Public Safety.~~]

[~~(B) Emergency situation–For the purpose of authorizing an oral prescription for a Schedule II substance, the term "emergency situation" means those situations in which the prescribing practitioner determines that:~~]

[~~*(i)* immediate administration of the controlled substance is necessary for proper treatment of the intended ultimate user;~~]

[~~*(ii)* no appropriate alternative treatment is available, including administration of a drug which is not a controlled substance under Schedule II; and~~]

[~~*(iii)* it is not reasonably possible for the prescribing practitioner to provide a written prescription to a pharmacist prior to the dispensing.~~]

[~~(C) Hospital–~~]

[~~*(i)* General hospital–Any establishment offering services, facilities, and beds for use beyond 24 hours for two or more nonrelated individuals requiring diagnosis, treatment, or care for illness, injury, deformity, abnormality, or pregnancy, and regularly maintaining at least clinical laboratory services, diagnostic x-ray services, treatment facilities which would include surgery and/or obstetrical care, and other definitive medical or surgical treatment of similar extent.~~]

[~~*(ii)* Special hospital–Any establishment offering services, facilities, and beds for use beyond 24 hours for two or more nonrelated individuals who are regularly admitted, treated, and discharged and require services more intensive than room, board, personal services, and general nursing care and which has clinical laboratory facilities, diagnostic x-ray facilities, treatment facilities, and/or other definitive medical treatment and has a medical house staff in regular attendance, and maintains records of the clinical work performed for each patient.~~]

[~~*(iii)* Ambulatory surgical center–Approved surgical centers licensed by the State Hospital Licensing Board and approved by Medicaid to do day surgery when a patient is not admitted beyond a 24-hour period.~~]

[~~(D) Institutional practitioner–~~]

[~~*(i)* An individual who meets each of the following qualifications:~~]

[~~*(I)* not yet licensed by the appropriate state professional licensing board;~~]

[~~*(II)* enrolled in a bona fide professional training program;~~]

[~~*(III)* in a base hospital or institutional training facility registered by the federal Drug Enforcement Administration; and~~]

[~~*(IV)* authorized by the base hospital or training institution to administer, dispense, or prescribe controlled substances.~~]

[~~*(ii)* Institutional practitioner shall be limited to interns, residents, fellows, or their equivalent.~~]

[~~(E) Medical purpose–The utilization of controlled substances for the purpose of relieving or curing mental or physical diseases or infirmities.~~]

[~~(F) Possession–The actual care, custody, control, or management.~~]

[~~(G) Prescribe–A direction or authorization, by prescription, permitting an ultimate user lawfully to obtain controlled substances from any person authorized by law to dispense such substances.~~]

[~~(H) Triplicate prescription–The official Texas Department of Public Safety prescription form utilized to administer, dispense, prescribe, or deliver a Schedule II narcotic and/or Schedule II-N nonnarcotic controlled substance to an ultimate user.~~]

[~~(I) Ultimate user–A person who has lawfully obtained and possesses a controlled substance for his own use or for the use of a member of his household or for administering to an animal owned by him or a member of his household.~~]

[~~(2) Special instructions. Information and special instruction information regarding procedures under these rules and regulations will be furnished upon request by writing to the Triplicate Prescription Section, Texas Department of Public Safety, P.O. Box 4087, Austin, Texas 78773.~~]

[~~(3) Purpose of issuing triplicate prescriptions.~~]

[~~(A) A prescription for a controlled substance to be effective must be issued for a legitimate medical purpose by an individual practitioner acting in the usual course of his professional practice. The responsibility for the proper prescribing and dispensing of controlled substances is upon the prescribing practitioner, but a corresponding responsibility rests with the pharmacist who fills the prescription. An order purporting to be a prescription not issued in the usual course of professional treatment or in legitimate and authorized research is not a prescription within the meaning and intent of the Texas Controlled Substances Act, §481.074 and the person knowingly filling such a purported prescription, as well as the person issuing it, may be subject to the penalties provided for violation of the provisions of law or rules relating to controlled substances.~~]

[~~(B) Prescriptions for Schedule II controlled substances shall be issued on the triplicate prescription form only and may not be refilled.~~]

[~~(4) Emergency dispensing of Schedule II controlled substances. No controlled substance in Schedule II may be administered, dispensed, prescribed, or delivered without the written prescription of a practitioner on a triplicate prescription form, except in emergency situations, as defined as follows.~~]

[~~(A) Schedule II controlled substances may be dispensed upon oral or telephonically communicated prescription of a practitioner or a practitioner's designated agent reduced promptly to writing by the pharmacy and filed by the pharmacy. Within 72 hours after authorizing an emergency oral prescription, the prescribing individual practitioner shall cause a written triplicate prescription, with the "Check if Emergency" block marked and indicating the emergency quantity prescribed to be delivered to the dispensing pharmacist. In addition to other requirements of the CFR, Title 21, Chapter 2, Part 1306.05, the prescription shall have written on its face "Authorization for Emergency Dispensing" and the date of the oral order. The federal regulation will be deemed satisfied by marking the block at the bottom of the triplicate prescription form indicating "Check if Emergency" and filling in "Date Issued" space at top of form.~~]

[~~(B) The written prescription may be delivered to the pharmacist in person or by mail, but if delivered by mail, it must be postmarked within the 72-hour period. Upon receipt, the dispensing~~

~~pharmacist shall attach Copy 2 of the triplicate prescription to the oral emergency prescription which has earlier been reduced to writing.]~~

~~[(C) The dispensing pharmacist shall send Copy 1 of the triplicate prescription to the Department of Public Safety within 30 days from the date the prescription is filled. Copy 2 of the triplicate prescription, along with the copy of the oral emergency prescription, will be retained by the pharmacy for two years for inspection purposes. No prescription for a Schedule II controlled substance may be refilled.]~~

~~[(5) Partial dispensing of Schedule II controlled substances.]~~

~~[(A) If unable to supply the full quantity called for in a written or emergency oral prescription for a Schedule II controlled substance, the pharmacist may partially dispense the prescription and complete the prescription under the following conditions.]~~

~~[*(i)* The pharmacist notes the initial partial quantity dispensed on the face of the written prescription or emergency oral prescription.]~~

~~[*(ii)* The remaining portion of the prescription is dispensed within 72 hours of the first partial dispensing. No further quantity may be dispensed beyond 72 hours without a new prescription.]~~

~~[*(iii)* If the remaining portion of the prescription is not or cannot be dispensed within the 72-hour period, the pharmacist shall notify the prescribing practitioner.]~~

~~[(B) A pharmacist may dispense a prescription for a Schedule II controlled substance in partial quantities to include individual dosage units, for a patient in a long-term facility (LTCF) or for a patient with a medical diagnosis documenting a terminal illness under the following conditions.]~~

~~[*(i)* The pharmacist must record on the prescription whether the patient is terminally ill or an LTCF patient. A prescription that is partially filled and does not contain the notation terminally ill or LTCF patient shall be deemed to have been filled in violation of the Texas Controlled Substances Act.]~~

~~[*(ii)* If there is any question about whether a patient may be classified as having a terminal illness, the pharmacist must contact the practitioner prior to partially filling the prescription. Both the pharmacist and the practitioner have a corresponding responsibility to assure that the controlled substance is for a terminally ill patient.]~~

~~[*(iii)* For each partial dispensing, the dispensing pharmacist shall record on the back of Copy 1 and Copy 2 of the prescription the:]~~

~~[*(I)* date of the partial dispensing;]~~

~~[*(II)* quantity dispensed;]~~

~~[*(III)* remaining quantity authorized to be dispensed; and]~~

~~[*(IV)* identification of the dispensing pharmacist.]~~

~~[*(iv)* Prior to any subsequent partial dispensing, the pharmacist must determine that the additional partial dispensing is necessary.]~~

~~[*(v)* The total quantity of the Schedule II controlled substances dispensed in all partial dispensings must not exceed the total quantity prescribed.]~~

~~[*(vi)* Schedule II prescriptions for patients in a long-term care facility or patients with a medical diagnosis documenting a terminal illness shall be valid for a period not to exceed 30 days from the issue date unless sooner terminated by discontinuance of the medication.]~~

~~[(6) Exceptions to use of triplicate prescriptions.]~~

~~[(A) A medication order written for a patient who is admitted to a hospital at the time the medication order is written and filled is not required to be on a triplicate prescription.]~~

~~[*(i)* "Medication order," as used in this subsection, will mean a drug order issued for administration to a patient admitted to a hospital.]~~

~~[*(ii)* "Admitted to a hospital," as used in this subsection, will include the following:]~~

~~[*(I)* general hospital, special hospitals, ambulatory surgical centers, and surgical suites in dental schools;]~~

~~[*(II)* hospital clinics and emergency room admittance, if the clinic and/or emergency room is under the control, direction, and administration as an integral part of the general or special hospital.]~~

~~[(B) A prescription written and filled for a patient who is admitted to a hospital at the time the prescription is written and filled is not required to be on a triplicate prescription; however, such prescription shall comply with the requirement of the Texas Pharmacy Act, §40(g).]~~

~~[*(i)* Schedule II controlled substances may be dispensed by a practitioner or pharmacy of the hospital to a patient who has been admitted to a hospital and who will require an emergency quantity of controlled substances upon release from the hospital. These Schedule II controlled substances may only be dispensed to a patient while such patient is still admitted to and a resident of the hospital.]~~

~~[*(ii)* The amount of Schedule II controlled substances dispensed under this paragraph may only be the amount needed for proper treatment of the patient until access to a pharmacy other than the hospital pharmacy is possible, but in no event may exceed a seven-day supply. However, when an emergency supply is dispensed from the emergency room of the hospital, the amount dispensed may not exceed a 72-hour supply.]~~

~~[*(iii)* The Schedule II controlled substances dispensed under the situations outlined in clause (ii) of this subparagraph must be in a properly labeled container.]~~

~~[(7) Pharmacist responsibilities.]~~

~~[(A) Upon receipt of Copy 1 and Copy 2 of a properly completed triplicate prescription from a practitioner, each dispensing pharmacist shall utilize the "Pharmacy Use Only" section and record the following:]~~

~~[*(i)* pharmacy name, address, area code/telephone number, and Drug Enforcement Administration number. This information may be printed, typed, or rubber stamped, or the pharmacist may use a label that is securely affixed in this area;]~~

~~[*(ii)* the dispensing pharmacist's signature shall be entered in a space located directly below the pharmacy information;]~~

~~[*(iii)* enter in the spaces provided the date filled and the pharmacy prescription number;]~~

~~[(iv) ensure that the drug prescribed and/or its substitute is legible on Copy 1 and Copy 2 of the triplicate prescription.]~~

~~[(B) No Schedule II prescription may be dispensed after the end of the seventh day following the date of issuance.]~~

~~[(C) a pharmacist may dispense a prescription that is orally or telephonically communicated by a practitioner or his designated agent for a Schedule II controlled substance in emergency situations, as defined by paragraph (1)(B) of this subsection.]~~

~~[(i) In such emergency situations the dispensing pharmacist shall reduce promptly to writing the following:]~~

~~[(I) name, address, and federal Drug Enforcement Administration number of the prescribing practitioner;]~~

~~[(II) drug prescribed, the dosage, and the instructions for use;]~~

~~[(III) name, address, and age of the person for whom the controlled substance is prescribed (or if an animal, the species and owner's name and address).]~~

~~[(ii) The pharmacist shall file the recorded information as set out in subparagraph (C)(i) of this paragraph in the pharmacy's Schedule II prescription files.]~~

~~[(iii) Within 72 hours from the time thee emergency oral or telephonic communication was received, the practitioner must provide the dispensing pharmacy with the triplicate prescription order corresponding to the oral prescription order. If such triplicate prescription is not provided, the pharmacist shall contact the Department of Public Safety and the Drug Enforcement Administration.]~~

~~[(iv) The practitioner is required to place the date issued on the triplicate prescription and such date shall be the date the practitioner or his designated agent communicated the emergency oral or telephonic prescription to the pharmacy.]~~

~~[(v) The practitioner shall check the block at the bottom of the triplicate prescription which indicates the prescription is an emergency order. If the practitioner fails to check such block, the pharmacist should do so.]~~

~~[(vi) The pharmacist shall attach Copy 2 to the oral emergency prescription which was reduced to writing upon receipt from the practitioner or practitioner's designated agent.]~~

~~[(D) Within 30 days from the date a pharmacist fills a triplicate prescription, the pharmacy is required to mail Copy 1 of the form to the Texas department of Public Safety, Triplicate Prescription Section, P.O. Box 4087, Austin, Texas 78773.]~~

~~[(E) Should a prescription be written on a triplicate prescription by a practitioner for a controlled substance other than a Schedule II, the pharmacist may dispense the prescription but shall mark the prescription in such a way as to clearly indicate that the drug dispensed is not a Schedule II controlled substance.]~~

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 23, 1999.

TRD-9909026
Gay Dodson, R.Ph.
Executive Secretary/Director
Texas State Board of Pharmacy
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 305-8028

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Subchapter F. NON-RESIDENT PHARMACY (CLASS E)

22 TAC §§291.101-291.105

The Texas State Board of Pharmacy proposes new §291.101, concerning Purpose, §291.102, concerning Definitions, §291.103, concerning Personnel, §291.104, concerning Operational Standards, and §291.105, concerning Records. The new rules, if adopted, will implement the recommendations of the Task Force on Non-Resident Pharmacies and Pharmacy Automation.

Gay Dodson, R.Ph., Executive Director/Secretary, has determined that, for the first five-year period the rule is in effect, there will be no additional fiscal implications for state or local government as a result of enforcing or administering the rule.

Ms. Dodson has determined that, for each year of the first five-year period the rule will be in effect, the public benefit anticipated as a result of enforcing the rule will be to protect the public through the effective control and regulation of non-resident pharmacies which provide pharmacy services to residents of Texas. These new rules primarily clarify statutory requirements which have been in existence for several years. Therefore, the economic impact on Class E (Non-Resident) Pharmacies is anticipated to be minimal. There are no anticipated economic costs to other small or large businesses or to other entities who are required to comply with this section as proposed.

Comments on the proposal may be submitted to Steve Morse, R.Ph., Director of Compliance, Texas State Board of Pharmacy, 333 Guadalupe Street, Suite 3-600, Box 21, Austin, Texas, 78701-3942.

The new rules are proposed under §§554.002, 554.051, and 554.005 of the Texas Pharmacy Act (Subtitle J, Chapters 551-564, Occupations Code). The Board interprets §554.002 of the Texas Pharmacy Act as authorizing the agency to protect the public through the effective control and regulation of the practice of pharmacy. The Board interprets §554.051 of the Texas Pharmacy Act as authorizing the agency to adopt rules for the proper administration and enforcement of the Act including adoption of rules for pharmacies located in another state. The Board interprets §554.005 of the Texas Pharmacy Act as authorizing the agency to regulate the delivery or distribution of prescription drugs as they relate to the practice of pharmacy and specify the minimum standards for the maintenance of prescription drug records.

The statutes affected by this rule: Occupations Code, Subtitle J.

§291.101. Purpose.

(a) The purpose of these rules is to provide standards for the operation of non-resident pharmacies (Class E) which dispense a prescription drug or device under a prescription drug order and deliver the drug or device to a patient in this state, by the United States mail, a common carrier, or a delivery service.

(b) These rules are in accordance with §554.051(a) and (b) of the Act which permit the board to make rules concerning the operation of licensed pharmacies in this state applicable to pharmacies licensed by the board that are located in another state. The board has determined that these rules are necessary to protect the health and welfare of the citizens of this state.

(c) Unless compliance would violate the pharmacy or drug laws or rules in the state in which the pharmacy is located, Class E Pharmacies are required to comply with the provisions of §291.101-291.105 of this chapter (relating to purpose, definitions, personnel, operational standards, and records).

§291.102. Definitions.

The following words and terms, when used in this subchapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Act–The Texas Pharmacy Act, Chapters 551-566, Occupations Code, as amended.

(2) Accurately as prescribed–Dispensing, delivering, and/or distributing a prescription drug order:

(A) to the correct patient (or agent of the patient) for whom the drug or device was prescribed;

(B) with the correct drug in the correct strength, quantity, and dosage form ordered by the practitioner; and

(C) with correct labeling (including directions for use) as ordered by the practitioner. Provided, however, that nothing herein shall prohibit pharmacist substitution if substitution is conducted in strict accordance with applicable laws and rules, including Subchapter A of Chapter 562 of the Texas Pharmacy Act relating to Prescription and Substitution Requirements.

(3) Board–The Texas State Board of Pharmacy.

(4) Class E pharmacy license or non-resident pharmacy license–A license issued to a pharmacy located in another state whose primary business is to:

(A) dispense a prescription drug or device under a prescription drug order; and

(B) to deliver the drug or device to a patient, including a patient in this state, by the United States mail, common carrier, or delivery service.

(5) Confidential Record–Any health related record, including a patient medication record, prescription drug order, or medication order that:

(A) contains information that identifies an individual; and

(B) is maintained by a pharmacy or pharmacist.

(6) Deliver or delivery–The actual, constructive, or attempted transfer of a prescription drug or device or controlled substance from one person to another, whether or not for a consideration.

(7) Dispense–Preparing, packaging, compounding, or labeling, in the course of professional practice, a prescription drug or device for delivery to an ultimate user or the user's agent under a practitioner's lawful order.

(8) Distribute–To deliver a prescription drug or device other than by administering or dispensing.

(9) Generically equivalent–A drug that is "pharmaceutically equivalent" and "therapeutically equivalent" to the drug prescribed.

(10) New prescription drug order–A prescription drug order that:

(A) has not been dispensed to the patient in the same strength and dosage form by this pharmacy within the last year;

(B) is transferred from another pharmacy; and/or

(C) is a discharge prescription drug order. (Note: furlough prescription drug orders are not considered new prescription drug orders.)

(11) Pharmaceutically equivalent–Drug products which have identical amounts of the same active chemical ingredients in the same dosage form and which meet the identical compendial or other applicable standards of strength, quality, and purity according to the United States Pharmacopoeia or other nationally recognized compendium.

(12) Pharmacist–For the purpose of this subchapter, a person licensed to practice pharmacy in the state where the Class E pharmacy is located.

(13) Pharmacist-in-charge–The pharmacist designated on a pharmacy license as the pharmacist who has the authority or responsibility for a pharmacy's compliance with statutes and rules pertaining to the practice of pharmacy.

(14) Practitioner–

(A) a person licensed or registered to prescribe, distribute, administer, or dispense a prescription drug or device in the course of professional practice in this state, including a physician, dentist, podiatrist, or veterinarian but excluding a person licensed under the Act;

(B) a person licensed by another state, Canada, or the United Mexican States in a health field in which, under the law of this state, a license holder in this state may legally prescribe a dangerous drug; or

(C) a person practicing in another state and licensed by another state as a physician, dentist, veterinarian, or podiatrist, who has a current federal Drug Enforcement Administration registration number and who may legally prescribe a Schedule II, III, IV, or V controlled substance, as specified under Chapter 481, Health and Safety Code, in that other state.

(15) Prescription drug order–An order from a practitioner or a practitioner's designated agent to a pharmacist for a drug or device to be dispensed.

(16) Therapeutically equivalent–Pharmaceutically equivalent drug products which, when administered in the same amounts, will provide the same therapeutic effect, identical in duration and intensity.

§291.103. Personnel.

As specified in §562.101(f) of the Act (relating to Supervision of Pharmacy), a Class E pharmacy shall be under the continuous on-site supervision of a pharmacist and shall designate one pharmacist licensed to practice pharmacy by the regulatory or licensing agency of the state in which the Class E pharmacy is located to serve as the pharmacist-in-charge of the Class E pharmacy license.

§291.104. Operational Standards.

(a) Licensing requirements.

(1) A Class E pharmacy shall register annually or biennially with the board on a pharmacy license application provided by the board, following the procedures specified in §291.1 of this title

(relating to Pharmacy License Application) and provide the following additional information specified in §560.052(c) of the Act (relating to Qualifications):

(A) evidence that the applicant holds a pharmacy license, registration, or permit issued by the state in which the pharmacy is located;

(B) the name of the owner and pharmacist-in-charge of the pharmacy for service of process;

(C) evidence of the applicant's ability to provide to the board a record of a prescription drug order dispensed by the applicant to a resident of this state not later than 72 hours after the time the board requests the record; and

(D) an affidavit by the pharmacist-in-charge which states that the pharmacist has read and understands the laws and rules relating to a Class E pharmacy.

(2) A Class E pharmacy which changes ownership shall notify the board within ten days of the change of ownership and apply for a new and separate license as specified in §291.4 of this title (relating to Change of Ownership).

(3) A Class E pharmacy which changes location and/or name shall notify the board within ten days of the change and file for an amended license as specified in §291.2 of this title (relating to Change of Location and/or Name).

(4) A Class E pharmacy owned by a partnership or corporation which changes managing officers shall notify the board in writing of the names of the new managing officers within ten days of the change, following the procedures in §291.3 of this title (relating to Change of Managing Officers).

(5) A Class E pharmacy shall notify the board in writing within ten days of closing.

(6) A separate license is required for each principal place of business and only one pharmacy license may be issued to a specific location.

(7) A fee as specified in §291.6 of this title (relating to Pharmacy License Fees) will be charged for the issuance and renewal of a license and the issuance of an amended license.

(8) The board may grant an exemption from the licensing requirements of this Act on the application of a pharmacy located in a state of the United States other than this state that restricts its dispensing of prescription drugs or devices to residents of this state to isolated transactions.

(b) Prescription dispensing and delivery.

(1) General.

(A) All prescription drugs and/or devices shall be dispensed and delivered safely and accurately as prescribed.

(B) The pharmacy shall maintain adequate storage or shipment containers and use shipping processes to ensure drug stability and potency. Such shipping processes shall include the use of packaging material and devices to ensure that the drug is maintained at an appropriate temperature range to maintain the integrity of the medication throughout the delivery process.

(C) The pharmacy shall utilize a delivery system which is designed to assure that the drugs are delivered to the appropriate patient.

(2) Drug regimen review.

(A) For the purpose of promoting therapeutic appropriateness, a pharmacist shall prior to or at the time of dispensing a prescription drug order, review the patient's medication record. Such review shall at a minimum identify clinically significant:

(i) inappropriate drug utilization;

(ii) therapeutic duplication;

(iii) drug-disease contraindications;

(iv) drug-drug interactions;

(v) incorrect drug dosage or duration of drug treatment;

(vi) drug-allergy interactions; and

(vii) clinical abuse/misuse.

(B) Upon identifying any clinically significant conditions, situations, or items listed in subparagraph (A) of this paragraph, the pharmacist shall take appropriate steps to avoid or resolve the problem including consultation with the prescribing practitioner. The pharmacist shall document such occurrences if the prescription is dispensed. The documentation shall:

(i) be maintained at the pharmacy for two years;

(ii) contain the following information:

(I) unique prescription number;

(II) patient name;

(III) date of the review if different from the dispensing date;

(IV) the name, initials, or identification code of the pharmacist who performed the review; and

(V) steps taken to resolve the problem; and

(iii) be available in a hard copy format, if so requested by an agent of the board.

(3) Patient counseling and provision of drug information.

(A) To optimize drug therapy, a pharmacist shall communicate to the patient or the patient's agent, information about the prescription drug or device which in the exercise of the pharmacist's professional judgment the pharmacist deems significant, such as the following:

(i) the name and description of the drug or device;

(ii) dosage form, dosage, route of administration, and duration of drug therapy;

(iii) special directions and precautions for preparation, administration, and use by the patient;

(iv) common severe side or adverse effects or interactions and therapeutic contraindications that may be encountered, including their avoidance, and the action required if they occur;

(v) techniques for self monitoring of drug therapy;

(vi) proper storage;

(vii) refill information; and

(viii) action to be taken in the event of a missed dose.

(B) Such communication:

(i) shall be provided with each new prescription drug order, once yearly on maintenance medications, and if the pharmacist deems appropriate, with prescription drug order refills. (For the purposes of this clause, maintenance medications are defined as any medication the patient has taken for one year or longer);

(ii) shall be provided for any prescription drug order dispensed by the pharmacy on the request of the patient or patient's agent;

(iii) shall be communicated orally in person unless the patient or patient's agent is not at the pharmacy or a specific communication barrier prohibits such oral communication; and

(iv) shall be reinforced with written information. The following is applicable concerning this written information:

(I) Written information designed for the consumer shall be provided.

(II) When a compounded product is dispensed, information shall be provided for the major active ingredient(s), if available.

(III) For new drug entities, if no written information is initially available, the pharmacist is not required to provide information until such information is available, provided:

(-a-) the pharmacist informs the patient or the patient's agent that the product is a new drug entity and written information is not available.

(-b-) the pharmacist documents the fact that no written information was provided; and

(-c-) if the prescription is refilled after written information is available, such information is provided to the patient or patient's agent.

(C) Only a pharmacist may orally provide drug information to a patient or patient's agent and answer questions concerning prescription drugs. Non-pharmacist personnel may not ask questions of a patient or patient's agent which are intended to screen and/or limit interaction with the pharmacist.

(D) If prescriptions are routinely delivered outside the area covered by the pharmacy's local telephone service, the pharmacy shall provide a toll-free telephone line which is answered during normal business hours to enable communication between the patient and a pharmacist.

(E) The pharmacist shall place on the prescription container or on a separate sheet delivered with the prescription container in both English and Spanish the local and toll- free telephone number of the pharmacy and the statement: "Written information about this prescription has been provided for you. Please read this information before you take the medication. If you have questions concerning this prescription, a pharmacist is available during normal business hours to answer these questions at (insert the pharmacy's local and toll-free telephone numbers)."

(F) The provisions of this paragraph do not apply to patients in facilities where drugs are administered to patients by a person required to do so by the laws of the state (i.e., nursing homes).

(G) Nothing in this subparagraph shall be construed as requiring a pharmacist to provide consultation when a patient or patient's agent refuses such consultation. The pharmacist shall document such refusal for consultation.

(c) Generic Substitution. Unless compliance would violate the pharmacy or drug laws or rules in the state in which the pharmacy is located:

(1) a pharmacist in a Class E pharmacy may dispense a generically equivalent drug product if:

(A) the generic product costs the patient less than the prescribed drug product;

(B) the patient does not refuse the substitution; and

(C) the prescribing practitioner authorizes the substitution of a generically equivalent product; or

(D) the practitioner or practitioner's agent does not clearly indicate that the oral or electronic prescription drug order shall be dispensed as ordered; and

(2) provided the pharmacist uses as a basis for the determination of generic equivalency, the publication, Approved Drug Products With Therapeutic Equivalence Evaluations and current supplements published by the Federal Food and Drug Administration within the limitations stipulated in that publication.

(d) Therapeutic Drug Interchange. A switch to a drug providing a similar therapeutic response to the one prescribed shall not be made without prior approval of the prescribing practitioner.

(1) The patient shall be notified of the therapeutic drug interchange prior to, or upon delivery, of the dispensed prescription to the patient. Such notification shall include:

(A) a description of the change;

(B) the reason for the change;

(C) whom to notify with questions concerning the change; and

(D) instructions for return of the drug if not wanted by the patient.

(2) The pharmacy shall maintain documentation of patient notification of therapeutic drug interchange which shall include:

(A) the date of the notification;

(B) the method of notification;

(C) a description of the change; and

(D) the reason for the change.

(e) Transfer of Prescription Drug Order Information. Unless compliance would violate the pharmacy or drug laws or rules in the state in which the pharmacy is located, a pharmacist in a Class E pharmacy may not refuse to transfer prescriptions to another pharmacy who is making the transfer request on behalf of the patient.

(f) Prescriptions for Schedule II controlled substances. Unless compliance would violate the pharmacy or drug laws or rules in the state in which the pharmacy is located, a pharmacist in a Class E pharmacy who dispenses a prescription for a Schedule II controlled substance issued on a Texas Official Prescription Form shall:

(1) mail a copy of the form to the Texas Department of Public Safety, Electronic Prescription Section, P.O. Box 4087, Austin, Texas 78773 within 30 days of dispensing; or

(2) electronically send the prescription information to the Texas Department of Public Safety per their requirements for electronic submissions within 30 days of dispensing.

§291.105. Records.

(a) Maintenance of records.

(1) Every record required to be kept under this section shall be kept by the pharmacy and be available, for at least two years

from the date of such record, for inspecting and copying by the board or its representative, and other authorized local, state, or federal law enforcement agencies.

(2) Records, except when specifically required to be maintained in original or hard-copy form, may be maintained in an alternative data retention system, such as a data processing system or direct imaging system provided;

(A) the records maintained in the alternative system contain all of the information required on the manual record; and

(B) the data processing system is capable of producing a hard copy of the record upon the request of the board, its representative, or other authorized local, state, or federal law enforcement or regulatory agencies.

(b) Civil litigation and complaint records. A Class E pharmacy shall keep a permanent record of:

(1) any civil litigation commenced against the pharmacy by a Texas resident; and

(2) complaints that arise out of a prescription for a Texas resident lost during delivery.

(c) Confidentiality.

(1) A Class E pharmacy shall provide adequate security of prescription drug order and patient medication records to prevent indiscriminate or unauthorized access to confidential health information. If prescription drug orders, requests for refill authorization, or other confidential health information are not transmitted directly between a pharmacy and a physician but are transmitted through a data communication device, confidential health information may not be accessed or maintained by the operator of the data communication device unless specifically authorized to obtain the confidential information by this subsection.

(2) Confidential records are privileged and may be released only to:

(A) the patient or the patient's agent;

(B) practitioners and other pharmacists if, in the pharmacist's professional judgment, the release is necessary to protect the patient's health and well-being;

(C) the board or to a person or another state or federal agency authorized by law to receive the confidential record;

(D) a law enforcement agency engaged in investigation of a suspected violation Chapter 481 or 483, Health and Safety Code, or the Comprehensive Drug Abuse Prevention and Control Act of 1970 (21 U.S.C. §801 et seq.);

(E) a person employed by a state agency that licenses a practitioner, if the person is performing the person's official duties; or

(F) an insurance carrier or third party payer authorized by a patient to receive such information.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 23, 1999.

TRD-9909027

Gay Dodson, R.Ph.

Executive Director/Secretary

Texas State Board of Pharmacy

Earliest possible date of adoption: February 6, 2000

For further information, please call: (512) 305-8028

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Chapter 309. GENERIC SUBSTITUTION

22 TAC §309.3

The Texas State Board of Pharmacy proposes amendments to Section 309.3 regarding refills of prescription drug orders. The proposed rule, if adopted, will amend the current language in §309.3(d)(2), which the Texas State Board of Pharmacy has been enjoined from enforcing, and will establish the list of narrow therapeutic index drugs subject to the provisions of §562.014 of the Texas Pharmacy Act (Occupations Code, Subtitle J, Chapters 551-567), as enacted by the 75th Legislature in Senate Bill 609.

Section 562.014 of the Texas Pharmacy Act requires that the Texas State Board of Pharmacy, in consultation with the Texas State Board of Medical Examiners, establish by rule a list of narrow therapeutic index drugs. The proposed amendments incorporate the recommendations of representatives of the Texas State Board of Pharmacy and the Texas State Board of Medical Examiners. Two members of each Board met and unanimously recommended that no drugs should be included on a list of narrow therapeutic index drugs as defined in §562.014 of the Texas Pharmacy Act (Occupations Code, Subtitle J, Chapters 551-567) and that the Federal Food and Drug Administration guidelines be recognized as the authority to determine generic equivalency.

This proposed amendment differs from two previous proposed rules which established a list of nine narrow therapeutic index drugs. This action was recommended by the Texas State Board of Pharmacy and Texas State Board of Medical Examiners representatives after reviewing summaries of extensive testimony received during two public hearings on the two previous proposed rules. The representatives also noted the following in their recommendations to the Board: (1) the Texas State Board of Pharmacy has never received a documented report of adverse health problems to a patient caused by the legal substitution of two drugs which are rated as generically equivalent by the Federal Food and Drug Administration in its publication, "Approved Drug Products with Therapeutic Equivalence Evaluations;" (2) the Federal Food and Drug Administration notes in their comments to previous proposed rules and in a January 28, 1998 letter that ". . . there are no documented examples of a generic product manufactured to meet its approved specifications that could not be used interchangeably with the corresponding brand-name drug;" (3) current rules in the Texas Administrative Code regarding substitution of generically equivalent drug products specify that pharmacists may only substitute products that are rated therapeutically equivalent in the "Approved Drug Products with Therapeutic Equivalence Evaluations" and its current supplements; (4) practitioners may prohibit substitution either by signing on the "Dispense as Written" line of a written prescription or by clearly indicating on an oral prescription that the brand name product must be dispensed; (5) the presence of certain drugs on a list of narrow therapeutic index drugs could leave practitioners with the impression that such drugs require less monitoring, which could result in problems; (6) the agency has received a letter from Senator Frank Madla, the author of Senate Bill 609, 75th Legislative Session, which stated that a null list would be appropriate and acceptable if the Board in its expert opinion determines that no special handling is warranted for any drug marketed as a generic substitute; and (7) the Texas State Board of Pharmacy in consultation with the Texas State Board of Medical Examiners would review the matter again if the Federal Food and Drug Administration determines that certain drug products require different steps when substituting equivalent products.

Gay Dodson, R.Ph., Executive Director/Secretary, has determined that, for the first five-year period the rule is in effect, there will not be fiscal implications for state or local governments since the proposed amendment makes no changes to current requirements for generic substitution.

Ms. Dodson also has determined that for each year of the first five-year period the rule will be in effect, the public benefit anticipated as a result of enforcing the rule will be the establishment of standards for generic substitution in Texas.

Comments on the proposal may be submitted to Gay Dodson, R.Ph., Executive Director, Texas State Board of Pharmacy, 333 Guadalupe Street, Suite 3-600, Box 21, Austin, Texas, 78701-3942.

The amendments are proposed under the following provisions of the Texas Pharmacy Act (Occupations Code, Subtitle J, Chapters 551-567): §554.002 which the Board interprets to mean that the purpose of the Act is to protect the public through the effective control and regulation of the practice of pharmacy; §554.051 which the Board interprets to give the Board the authority to adopt rules for the proper administration and enforcement of the Act; and; §562.014 which authorizes the Board, in consultation with the Texas State Board of Medical Examiners, to establish by rule a list of narrow therapeutic index drugs.

The statutes affected by this rule: Texas Pharmacy Act (Occupations Code, Subtitle J, Chapters 551-567)

§309.3. Prescription Drug Orders.

(a)-(c) (No change.)

(d) Refills.

(1) (No change.)

(2) Narrow therapeutic index drugs.

(A) The board, in consultation with the Texas State Board of Medical Examiners, has determined that no drugs shall be included on a list of narrow therapeutic index drugs as defined in Section 562.013, Occupations Code. The board has specified in Section 309.7 of this title (relating to dispensing responsibilities) that pharmacist shall use as a basis for determining generic equivalency, Approved Drug Products with Therapeutic Equivalence Evaluations and current supplements published by the Federal Food and Drug Administration, within the limitations stipulated in that publication.

(i) Pharmacists may only substitute products that are rated therapeutically equivalent in the Approved Drug Products with Therapeutic Equivalence Evaluations and current supplements.

(ii) Practitioners may prohibit substitution either by signing on the "Dispense as Written" line of a written prescription drug order or by clearly indicating on an oral prescription drug order that the brand name product must be dispensed.

(B) The board shall reconsider the contents of the list if the Federal Food and Drug Administration determines a new equivalence classification which indicates that certain drug products are equivalent but special notification to the patient and practitioner is required when substituting these products.

~~[(A) A prescription for a narrow therapeutic index drug on which a physician has originally allowed generic substitution may be refilled only by using the same drug product by the same manufacturer that the pharmacist last dispensed under the prescription, unless otherwise agreed to by the prescribing physician, prior to dispensing.]~~

~~[(B) If a pharmacist does not have the same drug product by the same manufacturer in stock to refill the prescription, the pharmacist may dispense a drug product that is generically equivalent if the pharmacist notifies:]~~

~~[*(i)* the patient, at the time the prescription is dispensed, that a substitution of the prescribed drug product has been made; and]~~

~~[*(ii)* the prescribing practitioner of the drug product substitution by telephone, facsimile, or mail, at the earliest reasonable time, but not later than 72 hours after dispensing the prescription.]~~

~~[(C) For the purpose of this subsection, narrow therapeutic index drugs shall be all oral dosage forms of the following:]~~

~~[*(i)* digoxin;]~~

~~[*(ii)* phenytoin;]~~

~~[*(iii)* warfarin sodium;]~~

~~[*(iv)* theophylline;]~~

~~[*(v)* levothyroxine;]~~

~~[*(vi)* carbamazepine;]~~

~~[*(vii)* valproic acid;]~~

~~[*(viii)* lithium;]~~

~~[*(ix)* divalproex sodium.]~~

~~[(D) The board, in consultation with the Board of Medical Examiners, shall review the list of narrow therapeutic index drugs subject to this subsection when deemed appropriate but at least every two years.]~~

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 23, 1999.

TRD-9909028
Gay Dodson, R.Ph.
Executive Director/Secretary
Texas State Board of Pharmacy
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 305-8028

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TITLE 25. HEALTH SERVICES

Part 5. CENTER FOR RURAL HEALTH INITIATIVES

Chapter 500. EXECUTIVE COMMITTEE FOR THE CENTER FOR RURAL HEALTH INITIATIVES

Subchapter G. PERMANENT FUND FOR RURAL HEALTH FACILITY CAPITOL IMPROVEMENT

25 TAC §§500.401-500.411

The Center for Rural Health Initiatives (center) proposes new §§500.401-500.411, relating to grants, loans and loan guarantees for capital improvements in rural health facilities, specifically rural hospitals.

These rules are proposed to implement a portion of Acts 1999, 76th Legislature, Chapter 1391 (HB 1676), which creates the Permanent Fund for Rural Health Facility Capital Improvement.

HB 1676 enacts the Government Code, §403.1065, which creates the Permanent Fund for Rural Health Facility Capital Improvement. HB 1676 allows the earnings of this fund to be appropriated to the center for providing grants, loans and loan guarantees to a public or nonprofit hospital located in a rural county. HB 1676 also enacts the Health and Safety Code, §§106.201-106.204 relating to the center's use of the earnings. These sections address grants, loans, and loan guarantees; however, the center proposes that grants and no interest loans be awarded, at least initially, because of the projected higher administrative cost of providing loans with interest rates or loan guarantees.

The sections are needed to accomplish the following: define terms in the legislation; provide the center's philosophy in making the grants, loans and loan guarantees; discuss the sources and allocation of funds; establish who is eligible to receive the grants, loans and loan guarantees; provide the requirements for receiving the grants, loans and loan guarantees; establish the procedures for grant announcements; establish the procedures for grant, loan and loan guarantee applications; describe the competitive review process; and outline the selection criteria for awarding grants, loans and loan guarantees.

The center's proposed definition for a rural county is derived from HB 1676 where it enacts Government Code §106.201. Grants, loans and loan guarantees for capital improvements will be made to a public or nonprofit hospital located in a rural county that has a population of 150,000 or less or with respect to a county that has a population of more than 150,000 and contains a geographic area that is not delineated as urbanized by the federal census bureau, that part of the county that is not delineated as urbanized.

The center would like comments on its proposal to award only grants and no interest loans initially and exclude loans with interest rates greater than 0 percent and loan guarantees because of the higher costs associated with administering the latter two mechanisms. The center would also like comments on the proposed definition of capital improvements. The center would like comments on the selection criteria. The center would like comments on whether the preferred criteria should be required or if there are additional criteria that should be preferred.

Robt. J. "Sam" Tessen, MS, Executive Director of the Center for Rural Health Initiatives, has determined that for the first five years the sections are in effect, there will be fiscal implications to state and local governments as a result of administering the sections as proposed.

The legislature directed that $50 million be placed in the Permanent Fund for Rural Health Facility Capital Improvement. The legislature appropriated the available earnings of the fund determined in accordance with the Government Code, §403.1068 for this biennium and allowed for the fund to include monies transferred at the direction of the legislature, payments of interest and principal on loans made under Health and Safety Code, Chapter 106, Subchapter G, fees collected under that subchapter, and gifts and grants to the fund. The estimated earnings for this biennium are $2.5 million per year. Based on appropriations for the first two years, the center estimates that for the next five years, the center will be appropriated $2.5 million per year.

In the General Appropriations Act, Article XII, Section 6, the legislature stated that the administrative costs to implement the provisions of HB 1676 may not exceed 3.0%, and grants and program costs must compose at least 97% of the expenditures to implement the provisions of the bill. Therefore, during this biennium, the center will spend no more than 3.0% of the appropriations from the fund ($75,000 for the Permanent Fund for Rural Health Facility Capital Improvement) for administrative costs of implementation.

It is estimated that all appropriations will be expended in grants, loans, program costs, and administrative costs each biennium. Note that, particularly in the first biennium, less than the total appropriation of $2.5 million for the Permanent Fund for Rural Health Facility Capital Improvement may be spend in one fiscal year of the biennium but the entire appropriation for the fund for the biennium will be spent by the end of the biennium.

It is estimated that there will be a positive impact on local governments in an amount equal to the amount of grants and loans local governments receive. Public or nonprofit hospitals located in a rural county are eligible to receive grants, loans and loan guarantees under the Permanent Fund for Rural Health Facility Capital Improvement, therefore some portion of the $2.5 million appropriated may be granted to hospital districts or counties or municipalities which own public hospitals.

Robt. J. "Sam" Tessen, MS, Executive Director of the Center for Rural Health Initiatives, has determined that for the first five years the sections are in effect, the public benefit anticipated is an increase in the capacity of these hospitals to be vital links in the health care safety net by providing them with funds to make innovative and/or necessary capital improvements directed toward increasing and/or maintaining availability of services in their communities. The anticipated cost to small businesses or micro-businesses (which are nonprofit hospitals) is the minimal costs to apply for a grant, loan, or loan guarantee on capital improvement projects proposed by the nonprofit hospital. There will be no anticipated impact on local employment.

Comments on the proposal may be submitted to Robt. J. "Sam" Tessen, MS, Executive Director, Center for Rural Health Initiatives, P.O. Drawer 1708, Austin, TX 78767-1708. (512) 479-8891. Comments will be accepted for 30 days following the date of publication of this proposal in the *Texas Register*.

The new sections are proposed under the Health and Safety Code, §106.202 which provides the center with the authority to adopt rules concerning the Permanent Fund for Rural Health Facility Capital Improvement; Health and Safety Code, §106.021 (j) which provides the center with the authority to adopt rules to implement chapter 106.

These new sections affect the Government Code, §403.1065 and the Health and Safety Code, §§106.201-106.204.

§500.401. Purpose.

(a) As authorized by the Government Code, §403.1065, and the Health and Safety Code, §106.201-106.204 relating to the Permanent Fund for Rural Health Facility Capital Improvement, the center shall institute and administer grants, loans, and loan guarantees under this subchapter.

(b) This subchapter governs the administration of the grants, loans, and loan guarantees; the submission and review of grant, loan and loan guarantee applications; and the award of the grants, loans and loan guarantees.

§500.402. Definitions.

The following words and terms, when used in this subchapter, shall have the following meanings unless the context clearly indicates otherwise.

(1) Closing date - Dates specified in the request for proposals as the dates on which applications must be received.

(2) Director - Executive Director of the Center for Rural Health Initiatives or his or her designee.

(3) Capital improvement - The acquisition, construction, or improvement of a facility, equipment, or real property for use in providing health services. The term includes designing, engineering, supervising, inspecting, surveying, and other expenses incidental to the acquisition, construction , or improvements, or the purchase of capital equipment, including information systems hardware and software, for a health facility.

(4) Public hospital - A general or special hospital licensed under the Health and Safety Code, Chapter 241 that is owned or operated by a municipality, county, municipality and county, hospital district, or hospital authority and that performs inpatient or outpatient services.

(5) Center - Center for Rural Health Initiatives.

(6) Capital equipment- Equipment of a value defined as capital by the rules of the Health Care Financing Administration for implementation of the Medicare program, or $500.00 single item cost, whichever is less.

(7) Rural county - A county that has a population in the most recent decennial United States census of 150,000 or less, or with respect to a county that has a population of more than 150,000 and contains a geographic area that is not delineated as urbanized by the federal census bureau, that part of the county that is not delineated as urbanized.

§500.403. Sources and Allocation of Funds.

(a) Funds for the grants, loans, and loan guarantees shall be provided in accordance with the Government Code, §403.1065, relating to the Permanent Fund for Rural Health Facility Capital Improvement and the Health and Safety Code, §106.201-106.204.

(b) All grants, loans and loan guarantees shall be awarded competitively according to the provisions of this subchapter. For each competitive process the Executive Director shall decide whether that particular process will result in the awards of grants, loans, loan guarantees, or a combination of these programs.

(c) Grants, loans and loan guarantees shall be made only to the extent that funds are appropriated and available.

(d) The center shall have the authority and discretion to:

(1) determine the purpose(s) of the grants, loans and loan guarantees pursuant to law and this subchapter;

(2) approve or deny grant, loan and loan guarantee applications;

(3) determine the number, size and duration of grants, loans and loan guarantees; and

(4) modify or terminate grants, loans, and loan guarantees.

(e) The center shall not be liable, nor shall grant, loan and loan guarantee funds be used, for any costs incurred by applicants in the development, preparation, submission, or review of applications.

§500.404. Eligibility for Grants, Loans and Loan Guarantees.

(a) A public or nonprofit hospital located in a rural county is eligible to apply for a grant, loan or loan guarantee.

(b) A hospital eligible to receive a grant, loan, or loan guarantee under this subchapter is not eligible to receive a grant from the Texas Department of Health from its Community Hospital Capital Improvement Fund.

§500.405. Requirements for Grants, Loans and Loan Guarantees.

(a) The center shall specify reasonable requirements for grant, loan and loan guarantee applications.

(b) Use of grant, loan and loan guarantee funds shall be restricted to capital improvements and shall not be used for operating expenses, debt retirement of the hospital or the owner of the hospital, or recruitment or retention of providers.

(c) Loans awarded will be made with an interest rate below the current market rate and may be made at no interest at the discretion of the center.

(d) Grant, loan and loan guarantee recipients shall submit periodic reports to the center, with content, form and time determined by the center.

§500.406. Procedures for Grant, Loan and Loan Guarantee Announcements.

(a) Before applications are requested, the department shall publish one or more notices of grant, loan and loan guarantee availability in the Texas Register. These notices shall also be distributed throughout the state through mail and electronic means. The notices will include details about the grants, loans, and loan guarantees, instructions for obtaining a request for proposals, and the names of persons to contact in the center for further information.

(b) The center shall maintain a list of persons to be notified of requests for proposals. Any person wanting to be placed on the list should contact: Executive Director, center for Rural Health Initiatives, Attention: Capital Improvement Fund Program Administrator, 211 E. 7th Street, Suite 915, Austin, TX 78701.

(c) The center shall develop and publish a request for proposals, which shall contain details concerning, but not limited to, the following:

(1) the nature and purpose(s) of the grant, loan or loan guarantee;

(2) the total amount of funds available for the grant, loan, and loan guarantee;

(3) the maximum and minimum dollar amounts that will be awarded for individual grantees, loan recipients or loan guarantee recipients;

(4) the information and format required for grant, loan, and loan guarantee applications;

(5) information about the criteria used to judge grant, loan and loan guarantee applications; and

(6) the closing date or dates.

§500.407. Procedures for Grant, Loan and Loan Guarantee Applications.

(a) The center may specify any reasonable requirements for grant, loan and loan guarantee applications, including, but not limited to, length, format, authentication, and supporting documentation.

(b) Applications that are incomplete or substantially inconsistent with the requirements of this subchapter may be rejected without further consideration at the discretion of the center.

(c) Applications received after the closing date will not be considered, unless the closing date is extended by the center.

(d) Applicants will be given a minimum of 60 calendar days to file applications after a request for proposals is published. Applications must be received by the center on or before the closing date specified in the request for proposals.

§500.408. Competitive Review Process.

(a) Each application shall be reviewed by the center for completeness, relevance to the published request for proposals, adherence to center policies, general quality, technical merit, and budget appropriateness.

(b) The center may invite an advisor or advisors to provide review and make recommendations concerning the grant process. Such advisor(s) may include any number of members from inside or outside the center, at the discretion of the director. Advisor(s) from outside the center shall receive no compensation or reimbursement for expenses. No advisor(s) shall be a current or potential applicant for a grant, loan, or loan guarantees on which the advisor(s) would be making recommendations, unless provision for independent review is made by the director.

(c) The center's review process shall be completed within 45 days after the closing date.

§500.409. Selection Criteria.

(a) No grant, loan or loan guarantee shall be approved unless, in the opinion of the center, it addresses only capital improvements and does not propose to expend funds for operating expenses, debt retirement, or recruitment or retention of practitioners.

(b) A grant, loan or loan guarantee application from a public hospital will be given preference over an application from a nonprofit hospital.

(c) Evaluation of a grant, loan or loan guarantee application will consider applicant information relating to criteria delineating the health care needs of the rural area and community served by the applicant, the financial need of the applicant related to the specific project, and the probability that the applicant will effectively and efficiently use the money obtained through the grant, loan or loan guarantee.

§500.410. Project Approval.

(a) Grant, loan and loan guarantee recipients shall execute a contract with the center. The contract shall detail items such as budget, reporting requirements, general provisions for center contracts, and any other specifics that might apply to the award.

(b) Grant, loan and loan guarantee recipients shall cooperate with the center in preparing reports to the Legislature as required by the Government Code, §403.1069.

§500.411. Continuation Funding.

(a) Grant, loan and loan guarantee recipients may be eligible for future funding and/or funding of a second or third type, under the program funding options. The center will consider the grant, loan and loan guarantee recipient's accomplishments, progress toward stated goals and objectives, award of past grants, and development of alternative funding. Applications shall be submitted in accordance with this subchapter.

(b) The center will award future or alternative grants, loans and loan guarantees after a review of applications in accordance with the provisions of this subchapter.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 21, 1999.

TRD-9908926
Robt. J. "Sam" Tessen
Executive Director
Center for Rural Health Initiatives
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 479-8891

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TITLE 28. INSURANCE

Part 1. TEXAS DEPARTMENT OF INSURANCE

Chapter 34. STATE FIRE MARSHAL

Subchapter J. STOVETOP FIRE SUPPRESSION DEVICE APPROVAL

28 TAC §§34.1001-34.1004

The Texas Department of Insurance proposes new §§34.1001 through 34.1004 under new Subchapter J concerning state fire marshal approval, through the commissioner of insurance, of residential stovetop fire suppression devices for purposes of eligibility for certain premium reductions. This proposal is necessary to implement legislation enacted by the 76th Legislature in Senate Bill 139. Senate Bill 139 amended Subchapter C, Chapter 5, by adding Article 5.33C to the Insurance Code, which allows insurers to offer an insurance premium discount for a correctly installed residential stovetop fire suppression device, as defined by the statute, that has been approved by the state fire marshal through the commissioner. Amendments to the Texas Personal Lines Manual are currently pending before the commissioner regarding provisions for optional credits for Homeowners and Dwelling policies for stovetop fire suppression devices in conformity with the legislation. The proposed subchapter applies only to residential stovetop fire suppression devices in use on or after January 1, 2000. The new legislation provides that a policyholder of a single-family or multifamily dwelling, apartment owner, or condominium owner is eligible for a premium reduction for homeowners insurance coverage or fire or commercial fire insurance coverage if the policyholder has correctly installed on the covered property a stovetop fire suppression device that has been approved by the state fire marshal through the commissioner. Because the legislation contemplates that it is the policyholder who installs the device and that the discount is granted for "a correctly installed and functioning stovetop fire suppression device," the authority of the state fire marshal is limited solely to approval of the device to qualify for an optional premium discount on certain homeowners, fire, and commercial fire insurance premiums. The current statute and rules relating to fire extinguishers (Insurance Code Article 5.43-1; 28 TAC Chapter 34, Subchapters D and E) regulate, among other things, the leasing, selling, installing, and servicing of fire extinguishers, and prohibit the sale or use of all fire extinguishers, systems, and equipment that are not labeled or listed by an approved testing laboratory pursuant to nationally recognized or laboratory developed standards. As with that statute and rules, the state fire marshal believes that it is the most appropriate and efficient method, in approving stovetop fire suppression devices for purposes of the premium discount, to do so with reference to product certification by nationally recognized testing facilities and methods. In developing this proposal, the state fire marshal's office reviewed existing recognized product performance standards developed by Underwriters Laboratories (UL), the American National Standards Institute (ANSI), the American Society for Testing and Materials (ASTM), Factory Mutual Research Corporation (FMRC) and the National Fire Protection Association (NFPA) in determining appropriate national testing and performance standards on which to base state fire marshal approval as indicated in the legislation. Currently, there is no single recognized national standard for residential stovetop fire suppression devices. The state fire marshal, therefore, proposes to utilize a combination of standards and test criteria developed by recognized product performance standards organizations that the state fire marshal believes would best demonstrate the integrity of the product, provide a minimum performance capability, and afford the user a minimum level of safety in safeguarding lives and property. Proposed §34.1001 states the purpose and application of proposed Subchapter J, and provides for the severability of the provisions of the subchapter. Proposed §34.1002 sets forth the definitions of the new subchapter which incorporates some of the definitions from the new legislation and which sets forth the requirements for an approved testing laboratory and a product performance standard. Proposed §34.1003 outlines the specific product performance standards from UL, adopted by reference by the commissioner, and where to access this information. Proposed §34.1004 provides the criteria necessary to obtain approval by the state fire marshal for residential stovetop fire suppression devices. It further requires that each device contain a certification mark of the approved testing laboratory and that each device sold must include a manual, as submitted to the approved testing laboratory, with the specifically identified instruction topics of installation, operation, recharge, inspection, and maintenance.

Consideration of the proposal will occur in a public hearing under Docket Number 2438 scheduled for 10:00 a.m. on February 8, 2000, in Room 100 of the William P. Hobby, Jr. State Office Building, 333 Guadalupe Street in Austin, Texas.

G. Mike Davis, state fire marshal, has determined that for each year of the first five years the proposed sections are in effect, there will be no fiscal impact to state government. There will be no fiscal implications for local government as a result of enforcing or administering the new standards, and no effect on the local economy or local employment.

Mr. Davis also has determined that for each year of the first five years that the new sections are in effect, the anticipated public benefit from enforcing and administering these sections is an efficient and consistent approval process for the regulation of residential stovetop fire suppression devices for purposes of the premium discount allowed under Insurance Code Article 5.33C. Additionally, the public will benefit from the adoption and enforcement of minimum product performance and testing standards. The effect of the proposed sections on large, small, and micro-businesses results mostly, if not entirely, from the legislative enactment of Senate Bill 139, 76th Legislature, which permits a reduction in premium for homeowners insurance coverage or fire or commercial fire insurance coverage to policyholders who correctly install, on the covered property, functioning residential stovetop fire suppression devices that have been approved by the state fire marshal. The cost of compliance with this proposed rule is the cost to manufacturers to have their product tested by an approved testing laboratory to the specified performance standards. The total estimated cost for this testing is dependent on the complexity of a specific suppression device and will be an equivalent cost, depending on the equivalency of the devices, for all persons and companies, including large, small, and micro-businesses, who engage in the business of manufacturing residential stovetop fire suppression devices. Based on the state fire marshal's experience with testing laboratories, it is difficult to estimate with any specificity the cost involved because of the complex differences with types of systems, but it is estimated that a manufacturer developing this product may expend a minimum of $100,000 to meet the performance standards. However, any manufacturer who has already complied with these standards will have no measurable additional costs. It is also anticipated that any increase in costs as a result of the proposal will be passed on to consumers and will ultimately be recouped by the manufacturer. The proposed new sections may not be waived for manufacturers of residential stovetop fire suppression devices who qualify as a small or micro-business because the statute mandates approval of these devices in order for them to be eligible for the premium discount. In addition, lesser standards would neither be legal nor feasible as the statute contemplates that the devices be adequate to protect against hazards.

Comments on the proposal to be considered by the department must be submitted by 5 p.m. on February 7, 2000, to Lynda H. Nesenholtz, General Counsel and Chief Clerk, Texas Department of Insurance, P.O. Box 149104, Mail Code 113-2A, Austin, Texas 78714-9104. An additional copy of the comments must be submitted to G. Mike Davis, State Fire Marshal, Texas Department of Insurance, P.O. Box 149221, Mail Code 108-FM, Austin, Texas 78714-9221.

The new sections are proposed pursuant to the Insurance Code Article 5.33C and the Insurance Code §36.001 (former Article 1.03A). The 76th Legislature enacted Senate Bill 139, which amended Subchapter C, Chapter 5, Insurance Code by adding Article 5.33C. Article 5.33C provides that a policyholder of a single-family or multifamily dwelling, apartment owner, or condominium owner is eligible for a premium reduction for homeowners insurance coverage or fire or commercial fire insurance coverage if the policyholder has correctly installed on the covered property a stovetop fire suppression device that has been approved by the state fire marshal through the commissioner and permits the commissioner to adopt rules necessary for the implementation of the article. Insurance Code, §36.001 (former Article 1.03A) authorizes the Commissioner of Insurance to adopt rules for the conduct and execution of the duties and functions of the Texas Department of Insurance only as authorized by a statute.

The following statutes are affected by the proposed sections: §§34.1001 - 34.1004 Insurance Code, Article 5.33C

§34.1001. Purpose and Application.

(a) The purpose of this subchapter is to administer the law set forth in the Insurance Code, Article 5.33C, regarding the approval by the state fire marshal, through the commissioner of insurance, of residential stovetop fire suppression devices installed so as to qualify for an optional premium discount on certain homeowners, fire, and commercial fire insurance premiums.

(b) The sections of this subchapter shall be known as and may be cited as the residential stovetop fire suppression device rules.

(c) This subchapter applies only to residential stovetop fire suppression devices in use on or after January 1, 2000.

(d) If any provision of this subchapter or the application thereof to any person or circumstance is held invalid for any reason, the invalidity shall not affect the other provisions or any other application of this subchapter which can be given effect without the invalid provisions or application. To this end, all provisions of this subchapter are declared to be severable.

§34.1002. Definitions.

The following words and terms, when used in this subchapter, shall have the following meanings.

(1) Approved testing laboratory - An organization, which lists equipment and appurtenances for use in compliance with a product performance standard, if it is currently accredited as a Nationally Recognized Testing Laboratory (NRTL) by the U.S. Department of Labor, Occupational Safety and Health Administration (OSHA) in accordance with the requirements of 29 CFR 1910.7 for that specific product, category of products or product performance standard.

(2) Certification mark - The mark owned, controlled, and registered by an approved testing laboratory and used to identify approval or listing of a product.

(3) Commissioner - The Commissioner of Insurance.

(4) Product performance standard - A standard for the composition and testing of a stovetop fire suppression device, to verify its scope of application, installation criteria, and minimum performance in accordance with its intended purpose.

(5) Stovetop fire suppression device - A device or assembly of devices that is mounted to the vent hood over a residential stovetop cooking surface and that protects against one or more hazards through suppressing or extinguishing fires.

§34.1003. Product Performance Standards.

The commissioner adopts by reference, as product performance standards, the following copyrighted documents, recommendations and appendices concerning residential stovetop fire suppression devices. The standards are published by and are available from Underwriters Laboratories, Incorporated (UL), 333 Pfingston Road, Northbrook, Illinois 60062-2096.

(1) UL 1254 "Standard for Pre-engineered Dry Chemical Extinguishing System Units."

(2) UL 299 "Dry Chemical Fire Extinguishers."

(3) UL Subject 300A "Outline of Investigation for Extinguishing System Units for Residential Range Top Cooking Surfaces."

§34.1004. Approval.

A stovetop fire suppression device will be considered approved by the State Fire Marshal, for the purpose of this subchapter, if:

(1) It has been tested by an approved testing laboratory and, at the time it was tested, meets the applicable approval criteria of the most recent edition of the following:

(A) UL 1254 "Standard for Pre-engineered Dry Chemical Extinguishing System Units" or UL 299 "Dry Chemical Fire Extinguishers", and

(B) UL Subject 300A "Outline of Investigation for Extinguishing System Units for Residential Range Top Cooking Surfaces."

(2) It carries the certification mark of the approved testing laboratory; and

(3) Installation, operation, recharge, inspection, and maintenance instruction manual(s), as submitted to the approved testing laboratory, are provided with each device sold.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 27, 1999.

TRD-9909042
Lynda Nesenholtz
General Counsel and Chief Clerk
Texas Department of Insurance
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 463-6327

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TITLE 31. NATURAL RESOURCES AND CONSERVATION

Part 1. GENERAL LAND OFFICE

Chapter 2. RULES OF PRACTICE AND PROCEDURE

31 TAC §2.24

The General Land Office proposes an amendment to §2.24, relating to Judicial Review. The proposed amendment would add a new subsection to §2.24, providing for the payment of the cost for preparation of the record in the appeal of contested administrative cases. This rule would require parties seeking judicial review of the Land Commissioner's orders to pay the cost of preparing the record for judicial review.

Cheryl MacBride, Deputy Commissioner for Administration, has determined that for each year of the first five years this rule is in effect, there will be no fiscal implications for units of state or local government as a result of enforcing or administering the rule.

Cheryl MacBride, Deputy Commissioner for Administration has determined that for the first five years this rule is in effect the public will benefit from this rule in that the costs associated with appeal of administrative decisions will be borne by the parties seeking such appeal rather than by a public agency. There is no anticipated cost to the owners of small businesses as a result of this rule. There is no anticipated economic cost, other than the cost of preparing the record for appeal, to persons who are required to comply with the subsection as proposed.

Comments may be submitted in writing to Ms. Melinda Tracy, Legal Services Division, General Land Office, 1700 North Congress Avenue, Room 626, Austin, Texas 78701-1495; facsimile number (512) 463-6311.

This action is proposed under the Administrative Procedure Act, §2001.177, which provides the agency with the authority to require a party who appeals a final decision in a contested case to pay the cost of preparation of the record of the agency proceeding that is required to be sent to the reviewing court. This action is also proposed under the Natural Resources Code, §31.051, which provides the Land Commissioner with the authority to make and enforce suitable rules consistent with the law.

The amendment does not affect any statute, code or article.

§2.24. Judicial Review.

(a) Not later than the 30th day after the date on which the commissioner's order is final, an aggrieved party may file a petition for judicial review.

(b) Judicial review of the order or decision of the commissioner shall be under the APA.

(c) The party who appeals a final order of the commissioner shall pay the cost of preparation of the original or certified copy of the record of the proceeding that is required to be sent to the reviewing court.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9908956
Larry R. Soward
Chief Clerk
General Land Office
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 305-9129

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TITLE 34. PUBLIC FINANCE

Part 3. TEACHER RETIREMENT SYSTEM OF TEXAS

Chapter 41. INSURANCE PROGRAMS [~~HEALTH CARE BENEFITS~~]

Subchapter B. LONG-TERM CARE, DISABILITY AND LIFE INSURANCE

34 TAC §41.15

(Editor's note: The Teacher Retirement System of Texas proposes for permanent adoption the new section it adopts on an emergency basis in this issue. The text of the new section is in the Emergency Rules section of this issue.)

The Teacher Retirement System of Texas (TRS) proposes a new §41.15 concerning the requirements to bid on insurance for school district employees and retirees. The proposed new rule will implement Insurance Code article 3.50-4A, which was passed by the 76th Legislature, 1999 in Senate Bill 1128. In addition, the proposal addresses a change in the title of Chapter 41 from Health Care Benefits to Insurance Programs to more accurately reflect the subject matter of the chapter and the addition of two new subchapter titles. The proposed new rule has been simultaneously adopted on an emergency basis.

In accordance with the new law, the proposed rule sets forth the requirements for the selection of contractors for new insurance plans established by Insurance Code article 3.50-4A, including long-term care insurance, optional permanent life insurance, and short-term and long-term disability insurance. The selection requirements include minimum premium income requirements and minimum capital and surplus requirements. These criteria are necessary to ensure financial stability and integrity of the new programs and are consistent with Insurance Code article 3.50-4A, §2(d), which provides that TRS may consider "ability to service contracts, past experiences, financial stability, and other relevant criteria." The proposed rule also requires contractors to administer enrollment, adjudication of claims and coordination of services for the applicable insurance plans and requires contractors to account for premiums collected and disbursed.

Ronnie Jung, Chief Financial Officer, has determined that for each year of the first five-year period the rule is in effect, there will be no fiscal implications to state or local governments as a result of enforcing or administering the rule.

Mr. Jung has also determined that for each year of the first five years the rule is in effect the public benefit anticipated will be that the insurance plans established by Insurance Code article 3.50-4A will be offered to school district employees and retirees in accordance with the new law. The proposed rule is not regulatory in nature, and applies only to carriers that choose to bid on the insurance plans established under the new law (no carrier is required to bid). Therefore, there are no anticipated economic costs to persons who are required to comply with the section as proposed, or to small businesses.

Comments on the proposal may be submitted to Charles L. Dunlap, Executive Director, 1000 Red River, Austin, Texas 78701.

The new section is proposed under the Government Code, Chapter 825, §825.102, which authorizes the Board of Trustees of the Teacher Retirement System to adopt rules for the administration of the funds of the retirement system. Further, it is adopted under Insurance Code article 3.50-4A, including §2(d), which provides that competitive bidding shall be required under rules adopted by TRS and that the rules may provide criteria to determine qualified carriers. In addition, it is adopted under Insurance Code article 3.50-4A §§3(a) and (b), which provide that

TRS shall adopt rules for the selection of contractors, that the rules must require the contractors to perform certain functions and that TRS may adopt other rules necessary to administer the program.

There are no other laws affected by this proposed rule.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9909018
Charles Dunlap
Executive Director
Teacher Retirement System of Texas
Proposed date of adoption: February 25, 2000
For further information, please call: (512) 391-2115

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TITLE 37. PUBLIC SAFETY AND CORRECTIONS

Part 1. TEXAS DEPARTMENT OF PUBLIC SAFETY

Chapter 1. ORGANIZATION AND ADMINISTRATION

Subchapter C. PERSONNEL AND EMPLOYMENT POLICIES

37 TAC §1.38

(Editor's note: The text of the following section proposed for repeal will not be published. The section may be examined in the offices of the Texas Department of Public Safety or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

The Texas Department of Public Safety proposes the repeal of §1.38, concerning Personnel Complaint Policy. The repeal of §1.38 is deemed necessary to implement changes resulting from the passage of Senate Bill 370 by the 76th Texas Legislature. This repeal is being proposed simultaneously with a proposal to adopt a new §1.38 that will better inform the public of the Department's personnel complaint policies.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the repeal is in effect there will be no fiscal implications for state or local government.

Mr. Haas also has determined that for each year of the first five years the repeal is in effect the public benefit anticipated as a result of enforcing the repeal will be clarification of department policy. There is no anticipated economic cost to individuals. There is no anticipated economic cost to small or large businesses.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The repeal is proposed pursuant to Texas Government Code, §411.006(4), which provides the director with the authority to adopt rules, subject to commission approval, considered necessary for the control of the department.

This repeal affects Texas Government Code, §411.006(4).

§1.38. Personnel Complaint Policy.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908980
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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The Texas Department of Public Safety proposes new §1.38, concerning Personnel Complaint Policy. The justification for this section is to implement changes made to Texas Government Code, §411.0195 as a result of the passage of Senate Bill 370 by the 76th Texas Legislature. This section describes the department's current procedures by which complaints are filed and resolved by the department and methods by which consumers and service recipients are notified of the name, mailing address, and telephone number of the department for the purpose of directing complaints to the department.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the rule is in effect there will be no fiscal implications to state or local government.

Mr. Haas also has determined that for each year of the first five years the rule is in effect the public benefit anticipated as a result of enforcing or administering the rule will be clarification of department policy on how to initiate personnel complaints. There is no anticipated economic cost to individuals. There is no anticipated economic cost to small or large businesses.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The new section is proposed pursuant to Texas Government Code, §411.0195 which states the director, by rule, shall establish methods by which consumers and service recipients are notified of the name, mailing address, and telephone number of the department for the purpose of directing complaints to the department.

Texas Government Code, §411.0195 is affected by this proposal.

§1.38. Personnel Complaint Policy.

(a) Purpose. The purpose of these rules is to set out how and where to file a complaint about the actions or behavior of an employee of the Texas Department of Public Safety in compliance with Texas Government Code §411.0195.

(b) Applicability. The policies and procedures described in this subchapter apply only to complaints made against an employee of the department either by another employee of the department or by a member of the public.

(c) Definitions. The following words and terms, when used in this subchapter, shall have the following meanings unless the context in which the word or term is used clearly indicates otherwise:

(1) Complaint - a written statement of allegations against an employee of the department made by a member of the public or another department employee which alleges one or more of the following:

(A) an infraction of department rules, regulations, or policies; or

(B) an illegal act.

(2) Complainant - a person who files a complaint.

(3) Department - the Texas Department of Public Safety.

(d) Filing a Complaint.

(1) Persons desiring to make a complaint must understand the importance of submitting their complaint in writing with signature affixed. (The Texas Government Code §614.022 provides that all complaints to be considered on law enforcement officers must be made in writing and signed by the person making the complaint.) If a complainant makes a complaint orally or by e-mail, he or she will be requested to submit the complaint in writing with their signature affixed, and given the necessary form and instructions to file the complaint. Complaint forms may be obtained from any department office or on the internet at the department's web page (www.txdps.state.tx.us).

(2) The completed and signed complaint may be filed with the employee's supervisor by United States mail or personal delivery, or by United States mail at Texas Department of Public Safety, Internal Affairs Unit, Box 4087, Austin, Texas 78773-0160.

(3) The name, mailing address, and telephone number of the person to whom the complaint should be directed may be obtained by calling:

(A) the department at its headquarters in Austin, Texas at (512) 424-2000, or

(B) by contacting any department office.

(4) A complaint should contain the following information:

(A) name, mailing address, and telephone number of the complainant;

(B) the name of the employee about which the complaint is being filed or sufficient information to enable the department to identify the employee; and

(C) a concise statement of the nature of the complaint, including all relevant facts.

(5) A summary of the department's complaint investigation process is available on the department's web page. A copy will be provided to any person who requests a complaint form or files a written complaint.

(e) Complaint Investigation and Resolution Procedures.

(1) A complete description of the department's complaint investigation, resolution, and appeal procedures may be found in Chapter 7A of the Department's General Manual which is on file with the Texas State Library located in Austin, Texas. A summary of this information is available on the department's web site.

(2) All written complaints filed with the department will be investigated thoroughly, objectively, and expeditiously. The complainant will be notified that the complaint is to be investigated, and the complainant will be contacted personally by the investigator if at all possible to discuss the complaint allegations in detail.

(3) The complainant and employee will be informed in writing of the resolution of the complaint.

(4) If the complaint investigation process is not complete within 90 days of the complaint being filed, the complainant and the employee will be notified of the complaint's status on a quarterly basis until final resolution.

(f) Anonymous or Unwritten Complaints. A complainant refusing to file a written complaint or who makes an anonymous complaint, does not necessarily prevent an investigation from being initiated on the facts provided. However, unwritten or anonymous complaints do cause the matter to be more difficult to process to an effective conclusion.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908981
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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Subchapter T. DISPOSITION OF FORFEITED ASSET

37 TAC §1.251

The Texas Department of Public Safety proposes new §1.251, concerning Disposition of Forfeited Asset. The new section promulgates the Public Safety Commission's policy and procedure to approve the Department of Public Safety's (DPS) disposition or other use of an asset forfeited to the department under federal or state law. The department must obtain prior commission approval before disposing of any asset except tangible property, such as a vehicle, firearm, or cellular telephone. The commission delegates its authority to approve disposition of tangible property to a major division chief if a report of the dispositions is made annually to the commission.

Tom Haas, Chief of Finance, has determined that for each year of the first-five year period the rule is in effect there will be no fiscal implications as a result of enforcing or administering the rule.

Mr. Haas also has determined that for each year of the first five years the rule is in effect the public benefit anticipated as a result of enforcing the rule will be to ensure oversight by the Public Safety Commission of all expenditures and other uses of a forfeited asset by the department. There is no anticipated economic cost to individuals or to small or large businesses.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The new section is proposed pursuant to Texas Government Code, §411.004(3), which authorizes the Public Safety Commission to adopt rules considered necessary for carrying out the department's work and pursuant to specific mandate and authority of Senate Bill 370 (Acts 76th Legislature, Regular Session, Chapter 1189, codified as Government Code, §411.0131).

Texas Government Code, §411.004(3) and §411.0131 are affected by this proposal.

§1.251. Public Safety Commission Approval of Disposition of a Forfeited Asset.

(a) The following words and terms, when used in this subchapter, shall have the following meanings, unless the context clearly indicates otherwise:

(1) Asset - refers to currency, a negotiable instrument, real property, tangible property, or other non-tangible property forfeited to the department under state or federal law. The term does not include controlled substance property or other contraband summarily forfeited or destroyed by the department under Health and Safety Code, Chapters 481-485.

(2) Disposition - refers to the use, transfer, sale, expenditure, or other disposition of an asset.

(b) Except as provided by Subsections (f) and (g) of this section, the department shall obtain commission approval of a proposed asset disposition.

(c) If the intended disposition involves an asset other than tangible property, the director or his designee shall submit a written request to the commission for approval.

(d) The written request shall include a description of the asset and its intended use.

(e) Before approving the disposition, the commission shall consider:

(1) how the disposition supports priorities established by the legislature in the department's strategic plan; and

(2) whether the disposition complies with applicable state and federal guidelines.

(f) The commission, by this rule, delegates to each major division chief its authority to approve the disposition of a forfeited asset that is tangible property.

(g) An annual report will be submitted to the commission detailing the disposition of all assets that are tangible property. This report shall include a statement of:

(1) how the disposition supports priorities established by the legislature in the department's strategic plan; and

(2) whether the disposition complies with applicable state and federal guidelines.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908982

Dudley M. Thomas

Director

Texas Department of Public Safety

Earliest possible date of adoption: February 6, 2000

For further information, please call: (512) 424-2135

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Chapter 15. DRIVERS LICENSE RULES

Subchapter A. LICENSING REQUIREMENTS

37 TAC §15.6, §15.7

The Texas Department of Public Safety proposes amendments to §15.6 and §15.7, concerning Licensing Requirements. Amendment to §15.6 changes the cubic centimeter piston displacement of a motorcycle that a 15 year old applicant, provided other requirements are met, may operate from 125cc to 250cc. Amendment to §15.7 changes the $50 reinstatement fee to a "statutory" reinstatement fee (currently $100). The amendments are necessary in order for the department to comply with Senate Bill 370 and House Bill 1492 passed during the 76th Texas Legislature, 1999.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the rules are in effect there will be a positive impact to state government due to the increase in reinstatement fee from $50 to $100. The anticipated increase in revenue for year 2000 is $11,464,529.00; the increase for year 2001 is $11,829,614.00; for year 2002, the increase is $12,210,871.00; for year 2003, the increase is $12,609,089.000; and for year 2004, the increase is $12,979,975.00. There is no anticipated impact on local government.

Mr. Haas also has determined that for each year of the first five years the rules are in effect the public benefit anticipated as a result of enforcing the rules will be to allow for the operation of a motorcycle that is better suited to be driven on public streets and highways and to clarify what the required reinstatement fee is. There is no anticipated cost to small or large businesses. The cost to individuals who are required to comply with the section as proposed will be the required statutory reinstatement fee.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The amendments are proposed pursuant to Texas Government Code, §411.004(3), which authorizes the Public Safety Commission to adopt rules, considered necessary for carrying out the department's work, and Texas Transportation Code, §521.005.

Texas Government Code, §411.004(3) and Texas Transportation Code, §521.005 are affected by this proposal.

§15.6. Motorcycle License.

A motorcycle license authorizes the driving of a motorcycle or motor-assisted bicycle. Three types of motorcycle licenses are issued. One is for all motorcycles of any size engine; one is for motor-driven cycles of 250 [~~125~~] cubic centimeter piston displacement or less; and one is for motor-assisted bicycles of less than 50 cubic centimeter piston displacement. A driver qualifying to operate both motorcycle and Class A, B, or C type vehicles will be issued one license showing both classes with restrictions when applicable.

(1) Motorcycle. Requires a Class M license.

(A) This authorizes operation of all motorcycles, motor-driven cycles, and mopeds.

(B) The minimum age is 16 years with completion of the classroom phase of driver education and the Department-Approved Basic Motorcycle Operator Training Course or Minor's Restricted Driver's License (MRDL) approval.

(2) Motor-Driven Cycle. Requires restricted Class M license.

(A) The minimum age is 15 years with completion of the classroom phase of driver education and the Department-Approved Basic Motorcycle Operator Training Course or Minor's Restricted Driver's License (MRDL) approval.

(B) The Class M license will be restricted to driving a motor-driven cycle with 250 [~~125~~] cubic centimeter piston displacement (Code I).

(3) Moped. Requires restricted Class M license.

(A) The minimum age is 15 years with parent or guardian authorization and pass the vision and written test. No road test is required.

(B) The Class M license will be restricted to driving a moped (Code K).

§15.7. Occupational License (Essential Need).

(a) An occupational license authorizes the driving of any motor vehicle subject to the restrictions imposed and is a special license issued without photograph by the Driver Improvement and Control Bureau in Austin upon authorization by a district court or county court. It may authorize the driving of any motor vehicle:

(1) in the performance of an occupation or trade or transportation to and from such occupation or trade;

(2) for transportation to and from an educational facility in which the person is enrolled; or

(3) in the performance of essential household duties.

(b) The person issued an occupational license is required to carry a certified copy of the court order showing the restrictions imposed by the court along with the license issued by Driver Improvement and Control Bureau and is required to show the court order and license to a peace officer on request.

(c) The basic requirements for the issuance of an occupational license are:

(1) a certified copy of petition and a copy of a legally issued certified court order finding an essential need for operating a motor vehicle as provided in subsection (a) of this section and setting forth the conditions for such driving; and

(2) the filing of an SR-22 and the maintenance of such proof of financial responsibility.

(d) The fee is $10 for one year. If the suspension is an automatic suspension or a safety responsibility suspension which has become effective, an additional statutory reinstatement fee[~~of $50~~] is required with the SR-22 form.

(e) The expiration date will be shown on the license and will be the first of the following dates, unless further extended by the court:

(1) when the suspension ends; or

(2) as determined by court order.

(f) A certified copy of the court order by itself may be used as a restricted license for a period of 30 days from the date of the order.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908984
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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Subchapter C. EXAMINATION REQUIREMENTS

37 TAC §15.57

The Texas Department of Public Safety proposes an amendment to §15.57, concerning Examination Requirements. Amendment to the section changes the cubic centimeter piston displacement of a motorcycle that a 15-year-old applicant, provided other requirements are met, may operate from 125cc to 250cc.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the rule is in effect there will be no fiscal implications to state or local government.

Mr. Haas also has determined that for each year of the first five year period the rule is in effect the public benefit anticipated as a result of enforcing the rule will be to allow for the operation of a motorcycle by 15 year old applicants that is better suited to be driven on public streets and highways. There is no anticipated economic cost to individuals or to small or large businesses.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The amendments are proposed pursuant to Texas Government Code, §411.004(3), which authorizes the Public Safety Commission to adopt rules, considered necessary for carrying out the department's work, and Texas Transportation Code, §521.005.

Texas Government Code, §411.004(3) and Texas Transportation Code, §521.005 are affected by this proposal.

§15.57. Restrictions, Physical.

Performance on the driving test generally establishes what effect physical disabilities may have on an applicant's driving. To assist the examining officer in arriving at a competent judgment, disabilities that are often encountered and the aids that are generally considered applicable for such conditions are outlined as follows.

(1)-(2) (No change.)

(3) Vehicle restrictions and endorsements.

(A) Unusual vehicles. If a motorcycle, motor-driven cycle, or other motor vehicle of unusual design which requires altogether different basic skills for driving is used for taking the road test, the applicant will be restricted to such vehicle.

(B) Horsepower. Driver's licenses issued to minors ages 15 to 18 on the basis of parental authorization only are restricted to "motorcycle only not to exceed 250 [~~125~~] cubic centimeter piston displacement" or "Moped only of less than 50 cubic centimeter piston displacement."

(4) (No change.)

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908978
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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Subchapter G. DENIAL OF RENEWAL OF DRIVER'S LICENSE FOR FAILURE TO APPEAR FOR TRAFFIC VIOLATION

37 TAC §§15.111, 15.112, 15.114, 15.116-15.119

The Texas Department of Public Safety proposes amendments to §§15.111, 15.112, 15.114, and 15.116-15.119, concerning Denial of Renewal of Driver's License for Failure to Appear for Traffic Violation. Amendments to the sections add additional offenses/violations for which a person may be denied renewal of their driver license for failure to appear to pay a fine involving an offense within justice and municipal court jurisdictions. The amendments are necessary in order for the department to comply with House Bill 2802 passed during the 76th Texas Legislature, 1999.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the rules are in effect there will be a positive fiscal impact on state and local government. However, based on the number of additional offenses added to this program and the fact that the department does not have access to these figures, we are not able to calculate the increase in revenues.

Mr. Haas also has determined that for each year of the first five years the rules are in effect the public benefit anticipated as a result of enforcing the rules will be to allow for a more efficient process for the courts to administer their failure to appear or payment of fines programs. There is no anticipated economic cost to small or large businesses. The anticipated cost to individuals who are required to comply with the sections as proposed will be the approximately $30 administration cost imposed by the courts.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The amendments are proposed pursuant to Texas Government Code, §411.004(3), which authorizes the Public Safety Commission to adopt rules, considered necessary for carrying out the department's work, and Texas Transportation Code, §706.012.

Texas Government Code, §411.004(3) and Texas Transportation Code, §706.012 are affected by this proposal.

§15.111. Purpose and Scope.

This section applies to denial of license renewal for failure to appear reported to the department under authority of Texas Transportation Code, Chapter 706, based on a complaint, citation, or court order to pay a traffic fine involving: [~~violations of traffic law occurring on and after September 1, 1995.~~]

(1) a violation of a traffic law;

(2) an offense under Texas Transportation Code, §543.009(b);

(3) an offense under Penal Code, §38.10, if the underlying offense is a traffic offense; or

(4) any other offense that a justice or municipal court has jurisdiction of under Code of Criminal Procedure, Article 4.11 or 4.14.

§15.112. Authority To Enter Interlocal Contract.

A political subdivision may contract with the department to provide information necessary for the department to deny renewal of the driver's license of a person who has failed to appear for a complaint, citation, or court order to pay a fine involving an offense listed in §15.111 of this title (relating to Purpose and Scope) [~~a violation of a traffic law.~~] A contract under this section must be made in accordance with Texas Government Code, Chapter 791. A contract made under this section is subject to the ability of the parties to provide or pay for the services required under the contract.

§15.114. Originating Court To File Failure To Appear Report.

If a person violated a promise to appear for an offense listed in §15.111 of this title (relating to Purpose and Scope) [~~a traffic violation~~], without good cause, a political subdivision shall submit a failure to appear report to the department. The political subdivision shall make reasonable efforts to ensure that each failure to appear report is accurate, complete, and nonduplicative. The report shall include the following information:

(1) the name of the political subdivision submitting the report;

(2) the jurisdiction in which the alleged offense occurred;

(3) the name, date of birth, and the Texas driver's license number of the person alleged to have committed the [~~traffic law~~]violation;

(4) the date of the alleged violation;

(5) the offense title or a brief description of the alleged [~~traffic law~~]violation;

(6) a statement that the person promised to appear and failed to appear as promised, and the date on which the person failed to appear; and

(7) any other information required by the department.

§15.116. Local [~~Traffic~~]Ordinances.

If the [~~traffic~~]offense alleged is a violation of local ordinance, but not state law, the political subdivision shall provide the department with a copy of the local ordinance alleged to have been violated, shall certify that the ordinance is currently in effect, and shall provide any other information required by the department. The department shall determine whether the local ordinance meets the statutory criteria for enforcement under this section.

§15.117. When Denial May Be Imposed.

On receipt of the necessary information from the political subdivision, the department may deny renewal of the person's driver's license for failure to appear based on a complaint, citation, or court order to pay a fine involving a violation of an offense listed in §15.111 of this title (relating to Purpose and Scope) [~~a traffic law~~]. Denial of renewal may occur at any time following an attempt to renew a license without regard to the expiration date of the current or previous license. Denial of renewal may occur at any time after the expiration of the current or previous license if a person does not attempt to renew his license. For purposes of this section, the department may deny renewal of an applicant's driver's license at any time before mailing the completed driver's license document.

§15.118. Clearance Report.

A clearance report is required to be filed by the political subdivision when there is no cause to continue to deny renewal of a person's driver's license based on the person's previous failure to appear[~~for a traffic violation~~]. In all cases when a clearance report is required, the political subdivision shall notify the department or the department's designee within one business day. The clearance report shall contain the following information:

(1) the name of the political subdivision submitting the report;

(2) the jurisdiction in which offense occurred;

(3) the name, date of birth, and the Texas driver's license number of the person alleged to have committed the <u>offense</u> [~~traffic law violation~~];

(4) the date of the alleged violation;

(5) the offense title or a brief description of the alleged [~~traffic law~~]violation;

(6) the basis for the clearance;

(7) whether a fee was required;

(8) whether a required fee was paid; and

(9) any other information required by the department.

§15.119. Clearance Report When No Fee Is Required.

(a) If the court finds that the license holder has established good cause for having previously failed to appear, the court shall file an appropriate clearance report to the department without requiring the license holder to pay a fee. For purposes of this section, "good cause" means a reasonable excuse such as would constitute a defense to a criminal prosecution for failure to appear. Examples of good cause are: death of a close family member; a serious, sudden accident or illness; required military service; or confinement.

(b) If the person who failed to appear is acquitted of the underlying traffic charge for which the failure to appear report was filed, the court shall file an appropriate clearance report without requiring the license holder to pay a fee. Acquittal means an official fact-finding made in the context of the adversary proceeding by an individual or group of individuals with the legal authority to decide the question of guilt or innocence. For purposes of this section, acquittal also includes a dismissal by the court upon proof of actual innocence. A person is not considered to have been acquitted of the traffic charge if the court imposes any conditions upon dismissal of the traffic complaint, such as penalties, court costs, educational programs, a period of probation, or any other sanction. For purposes of this section, a person is not considered to have been acquitted, and the prescribed administrative fee shall apply, in all cases that are dismissed under [~~Texas Transportation Code, Chapter 543, Subchapter B, or under~~]Texas Code of Criminal Procedure[~~, Article 45.54~~].

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908983
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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Chapter 25. SAFETY RESPONSIBILITY REGULATIONS

37 TAC §25.18

The Texas Department of Public Safety proposes an amendment to §25.18, concerning Fees. Amendment to the section deletes subsection (a), reformats subsection (b) and changes the section title. The amendment removes unnecessary language and changes the $50 reinstatement fee to "statutory" reinstatement fee. The amendment is necessary in order for the department to comply with Senate Bill 370 passed during the 76th Texas Legislature, 1999.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the rule is in effect there will be a positive impact to state government due to the increase in reinstatement fee from $50 to $100. The anticipated increase in revenue for year 2000 is $11,464,529.00; the increase for year 2001 is $11,829,614.00; for year 2002, the increase is $12,210,871.00; for year 2003, the increase is $12,609,089.00; and for year 2004, the increase is $12,979,975.00. There is no anticipated impact on local government.

Mr. Haas also has determined that for each year of the first five years the rule is in effect the public benefit anticipated as a result of enforcing the rule will be to clarify what the required reinstatement fee is. There is no anticipated cost to small or large businesses. The cost to individuals who are required to comply with the section as proposed will be the required statutory reinstatement fee.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The amendments are proposed pursuant to Texas Government Code, §411.004(3), which authorizes the Public Safety Commission to adopt rules, considered necessary for carrying out the department's work, and Texas Transportation Code, §521.005.

Texas Government Code, §411.004(3) and Texas Transportation Code, §521.005 are affected by this proposal.

§25.18. <u>Reinstatement</u>[~~Fees~~].

[~~(a) No statutory filing fee is required if:~~]

[~~(1) financial responsibility by insurance is shown;~~]

[~~(2) the party was legally parked or stopped;~~]

[~~(3) nonconsent applies to the owner;~~]

[~~(4) the party is not the owner of the vehicle;~~]

[~~(5) the accident occurred on private property;~~]

[~~(6) the parties are exempted from paying the fee by reason of governmental immunity;~~]

~~[(7) there is an affidavit of no suspended items; or]~~

~~[(8) there is no probability of judgment.]~~

[~~(b)~~] ~~Proof of financial responsibility maintained by a certificate of insurance must be filed on Form SR-22.~~] When a party's license and registrations have been suspended, a statutory[~~$50~~] reinstatement fee and proof of financial responsibility are prerequisites for the withdrawal of such suspension. When a party's license and registrations are suspended in several cases and proof of financial responsibility is required in each case, only one statutory[~~$50~~] reinstatement fee is required.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9908976

Dudley M. Thomas

Director

Texas Department of Public Safety

Earliest possible date of adoption: February 6, 2000

For further information, please call: (512) 424-2135

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Chapter 29. PRACTICE AND PROCEDURE

37 TAC §§29.1-29.49, 29.101-29.157

(Editor's note: The text of the following sections proposed for repeal will not be published. The sections may be examined in the offices of the Texas Department of Public Safety or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

The Texas Department of Public Safety proposes the repeal of §§29.1-29.49 and §§29.101-29.157 concerning Practice and Procedure. The sections are proposed for repeal because the department no longer conducts its own formal administrative hearings. The State Office of Administrative Hearings, pursuant to statutory authority, now conducts these hearings. The repeal of these sections removes those rules which are duplicated elsewhere or which conflict with other statutory or regulatory provisions. This action is being filed simultaneously with a proposal for new §§29.1-29.34 which provide general procedures for administrative hearings held under Texas Transportation Code, Chapters 548, 643, and 644.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the repeals are in effect there will be no fiscal implications to state or local government.

Mr. Haas also has determined that for each year of the first five-year period the repeals are in effect the public benefit anticipated as a result of enforcing the repeal will be the removal of obsolete or duplicative rules and an overall improvement in the accessibility and clarity of the adopted rules. There is no anticipated economic cost to individuals. There is no anticipated economic cost to small or large businesses.

Comments on the repeal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The repeals are proposed pursuant to Texas Government Code, §411.004(3), which authorizes the Public Safety Commission to adopt rules considered necessary for carrying out the department's work and Texas Transportation Code, §§548.002, 643.003, and 644.003.

Texas Government Code, §411.004(3) and Texas Transportation Code, §§548.002, 643.003 and 644.003 are affected by these repeals.

§29.1. Definitions.

§29.2. Object.

§29.3. Scope.

§29.4. Filing of Documents.

§29.5. Computation of Time.

§29.6. Agreements To Be in Writing.

§29.7. Service in Rulemaking Proceedings.

§29.8. Service in Nonrulemaking Proceedings.

§29.9. Conduct and Decorum.

§29.10. Classification of Parties.

§29.11. Parties in Interest.

§29.12. Appearances Personally or by Representative.

§29.13. Classification of Pleadings.

§29.14. Form and Content of Pleadings.

§29.15. Examination by the Director.

§29.16. Motions.

§29.17. Amendments.

§29.18. Incorporation by Reference of Agency Records.

§29.19. Licenses.

§29.20. Contested Proceedings.

§29.21. Personal Service.

§29.22. Prehearing Conference.

§29.23. Motions for Postponement, Continuance, Withdrawal, or Dismissal of Applications or Other Matters before the Commission or the Agency.

§29.24. Place and Nature of Hearings.

§29.25. Presiding Officer.

§29.26. Order of Procedure.

§29.27. Reporters and Transcript.

§29.28. Formal Exceptions.

§29.29. Dismissal without Hearing.

§29.30. Rules of Evidence.

§29.31. Documentary Evidence and Official Notice.

§29.32. Prepared Testimony.

§29.33. Limitations on Number of Witnesses.

§29.34. Exhibits.

§29.35. Offer of Proof.

§29.36. Depositions.

§29.37. Proposals for Decision.

§29.38. Filing of Exceptions, Briefs, and Replies.

§29.39. Form and Content of Briefs, Exceptions, and Replies.

§29.40. Oral Argument.

§29.41. Final Decisions and Orders.

§29.42. Administrative Finality.

§29.43. Motions for Rehearing.

§29.44. Rendering of Final Decision or Order.

§29.45. The Record.

§29.46. Ex Parte Consultations.

§29.47. Suspension of Rules.

§29.48. Amendments to Rules.

§29.49. Effective Date.

§29.101. Definitions.

§29.102. Scope.

§29.103. Institution of Penalty Proceeding.

§29.104. Filing of Documents.

§29.105. Computation of Time.

§29.106. Agreements To Be in Writing.

§29.107. Service of Notice of Hearing.

§29.108. Service of Pleadings and Motions.

§29.109. Conduct and Decorum.

§29.110. Classification of Parties.

§29.111. Parties-in-Interest.

§29.112. Appearances Personally or by Representative.

§29.113. Classification of Pleadings.

§29.114. Form and Content of Pleadings.

§29.115. Examination by the Judge.

§29.116. Motions.

§29.117. Amendments.

§29.118. Incorporation by Reference to Department Records.

§29.119. Consolidation.

§29.120. Informal Disposition.

§29.121. Prehearing Conference.

§29.122. Motions for Postponement, Continuance, Withdrawal, Dismissal, or Other Matters.

§29.123. Venue.

§29.124. Presiding Officer.

§29.125. Order of Procedure.

§29.126. Reporters and Transcription.

§29.127. Formal Exceptions.

§29.128. Dismissal without Hearing.

§29.129. Rules of Evidence.

§29.130. Documentary Evidence and Official Notice.

§29.131. Prepared Testimony.

§29.132. Limitations on Number of Witnesses.

§29.133. Exhibits.

§29.134. Offer of Proof.

§29.135. Discovery-General.

§29.136. Depositions.

§29.137. Admissions of Facts and Genuineness of Documents.

§29.138. Interrogatories.

§29.139. Discovery and Production for Inspection.

§29.140. Discovery Motions and Sanctions.

§29.141. Subpoena.

§29.142. Failure To Attend Hearing; Default Judgment.

§29.143. Entry of Appearance; Continuance.

§29.144. Proposal for Decision.

§29.145. Proof of Attorney's Fees, Costs, and Expenses of the State.

§29.146. Filing of Exceptions, Briefs, and Replies.

§29.147. Form and Content of Briefs, Exceptions, and Replies.

§29.148. Final Decisions and Orders.

§29.149. Administrative Finality.

§29.150. Motions for Rehearing.

§29.151. Rendering of Final Decision or Order.

§29.152. Judicial Review.

§29.153. The Record.

§29.154. Certified Record.

§29.155. Ex Parte Consultations.

§29.156. Conflicts.

§29.157. Effective Date.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9908987
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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37 TAC §§29.1-29.34

The Texas Department of Public Safety proposes new §§29.1-29.34, concerning Practice and Procedure. The new sections provide general procedures for administrative hearings held under Texas Transportation Code, Chapters 548 and 644. These chapters require hearings on denial, revocation or suspension of certification of inspection stations and inspectors; and hearings on administrative penalties assessed against commercial motor carriers for violations of motor carrier rules. The new sections are proposed simultaneously with the repeal of current §§29.1-29.49 and 29.101-29.157.

The new sections are necessary to accurately reflect current law and agency practices with regard to contested cases. The current rules are out of date and no longer used because the department does not conduct its own formal hearings as was the case when the rules were originally adopted in 1976. Date conflict with other rules and those of the State Office of Administrative Hearings (SOAH), causing confusion concerning their applicability. The proposed rules apply to Motor Carrier Hearings and Vehicle Inspection Hearings that are held before SOAH. The proposed rules remove unnecessary duplication of applicable SOAH rules and statutory provisions of the Texas Administrative Procedures Act. The proposed rules also supplement SOAH rules on these contested cases in order to more adequately address department-specific issues such as manner of service, notices of hearing, and informal dispositions.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the new sections are in effect there will be no fiscal implications for state or local government.

Mr. Haas also has determined that for each year of the first five years the rules are in effect the public benefit anticipated as a result of enforcing the rules will be rules that are more streamlined and less confusing. There is no anticipated economic cost to individuals. There is no anticipated economic cost to small or large businesses.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The new sections are proposed pursuant to Texas Government Code, §411.004(3), which authorizes the Public Safety Commission to adopt rules considered necessary for carrying out the department's work and Texas Transportation Code, §§548.002 and 644.003, which authorize the department to adopt rules to administer and enforce programs regulating vehicle inspection stations and inspectors, and commercial motor vehicle safety standards.

Texas Government Code, §411.004(3) and Texas Transportation Code, §§548.002 and 644.003 are affected by this proposal.

§29.1. Definitions.

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) APA-refers to The Administrative Procedures Act, Texas Government Code §2001.001, et seq.

(2) Contested case-refers to a contested case as defined by APA.

(3) Department-refers to the Department of Public Safety.

(4) Director-refers to the director of the Department of Public Safety or the designee of the director.

(5) Intervenor-refers to any party not otherwise defined.

(6) Judge-refers to the administrative law judge or hearing examiner assigned to hear a contested case and prepare a proposal for decision for the director or the director's designee.

(7) Movant-refers to the party who files a motion.

(8) Non-movant-refers to any party other than the party filing a motion.

(9) Party-refers to each person or agency named or admitted in a contested case.

(10) Petitioner-refers to the party classification of the department after it has instituted a contested case.

(11) Respondent-refers to a party against whom a contested case has been instituted by the department.

(12) SOAH- refers to the State Office of Administrative Hearings.

§29.2. Scope.

These rules shall govern the procedure for the institution, conduct and determination of all contested cases arising under the department's jurisdiction with the exception of cases arising under Texas Transportation Code, Chapters 521, 522, 524, and 724. These rules do not apply to internal personnel matters of the department.

§29.3. Institution of a Contested Case.

(a) A contested case shall be instituted by the department after a person has requested a hearing or declined a penalty.

(b) Upon receipt of a setting for a hearing in a contested case, the department shall serve a notice of hearing upon the respondent.

(c) A notice of hearing shall include the following:

(1) a statement of the nature of the hearing;

(2) a statement of the date, time, and place of the hearing;

(3) a statement of the legal authority and jurisdiction under which a hearing is to be held;

(4) a reference to the particular sections of the statutes and rules involved;

(5) a short, plain statement of the matters asserted, including the recommended penalty or action;

(6) the following language in capital letters in at least 10-point boldface type: "YOUR FAILURE TO APPEAR AT THE HEARING WILL RESULT IN THE ALLEGATIONS AGAINST YOU SET OUT IN THIS NOTICE BEING ADMITTED AS TRUE, AND THE RELIEF SOUGHT IN THIS NOTICE OF HEARING MAY BE GRANTED BY DEFAULT"; and

(7) the language provided under §29.11(e) of this title (relating to Entry of Appearance; Continuance).

(d) After a hearing has been set, any party may move for appropriate relief, including, but not limited to, prehearing conferences, discovery, evidentiary rulings, continuances, and settings.

(e) A notice of hearing shall be served in accordance with the procedure set out in §29.5 (relating to Service of Notice of Hearing for Contested Cases-Motor Carrier) or §29.6 (relating to Service of Notice of Hearing for Contested Cases-Other) of this title. An amended notice of hearing may be served in accordance with §29.9 of this title (relating to Service of Pleadings and Motions).

§29.4. Agreements To Be in Writing.

No stipulation of agreement between the parties, their attorneys or representatives, with regard to any matter involved in any proceeding under this title shall be enforced unless it shall have been reduced to writing and signed by the parties or their authorized representatives, or unless it shall have been dictated into the record by them during the course of a hearing, or incorporated in an order bearing their written approval. This section does not limit a party's ability to waive, modify, or stipulate any right or privilege afforded by these rules, unless precluded by law.

§29.5. Service of Notice of Hearing for Contested Cases-Motor Carrier.

(a) Registered motor carriers: A notice of hearing shall be served on a respondent who is a motor carrier that is registered with the Texas Department of Transportation by certified mail, return receipt requested, or by personal delivery at:

(1) the last known address as reflected in the records or investigation of the department, or

(2) an alternative address specified in writing to the department by the respondent or the respondent's authorized representative after receipt of a notice of claim under §3.62 of this title (relating to Regulations Governing Transportation Safety), or

(3) the address registered by the motor carrier with the Texas Department of Transportation.

(b) Unregistered motor carriers and other persons. A notice of hearing shall be served on a person who is an unregistered motor carrier or other person subject to administrative penalties under Texas Transportation Code, Chapter 644, by certified mail, return receipt requested, or by personal delivery, and addressed to the last known address of the motor carrier or other person as reflected in the records of investigation of the department.

(c) Commercial driver's license. A notice of hearing shall be served on a person who holds a commercial driver's license and is subject to administrative penalties under Texas Transportation Code, Chapter 644, by serving the notice on the last known address provided to the department or other governmental authority that issued the license by certified mail, return receipt requested, or personal delivery.

§29.6. Service of Notice of Hearing for Contested Cases-Other.

A notice of hearing shall be served on a respondent by certified mail, return receipt requested, or by personal delivery, and addressed to at least one of the following:

(1) if respondent is an individual, the last known address of the respondent;

(2) if respondent is a corporation, the legal agent for service of process at the address registered with the Texas Secretary of State; or

(3) the last known address of the respondent as reflected in the records or investigation of the department.

§29.7. Notice of hearing.

(a) Service. A notice of hearing shall be served by the department after SOAH has issued a setting. Service of the notice of hearing by mail shall be complete upon deposit of the notice enclosed in a post-paid and properly addressed envelope in a post office or official depository under the care and custody of the United States Postal Service. Service by personal delivery shall be complete at the time of delivery.

(b) Certification. A certification filed by an authorized representative of the department certifying that the notice of hearing was served in accordance with this section shall be filed with SOAH and constitute prima facie evidence of service in compliance with this rule.

§29.8. Computation of Time.

Unless otherwise required by statute, in computing time periods prescribed by this chapter or by a judge's order, the day of the act, event, or default on which the designated period of time begins to run is not included. The last day of the period is included, unless it is a Saturday, a Sunday, or an official State holiday. When these rules specify a deadline or set a number of days for filing documents or taking other actions, the computation of time shall be by calendar days rather than business days, unless otherwise provided in this chapter or a judge's order. However, if the period to act is five days or less, the intervening Saturdays, Sundays, and legal holidays are not counted.

§29.9. Service of Pleadings and Motions.

(a) After the institution of proceedings, all pleadings, pleas, motions, discovery requests and any other documents that are filed or served by respondents and/or intervenors on the department, or any employee of the department, shall be served on the department's named attorney of record at the address identified in the notice of hearing or complaint.

(b) All pleadings, pleas, or motions shall be served by certified mail, return receipt requested, facsimile transmission, personal delivery, or overnight carrier.

§29.10. Parties-in-Interest.

Any party-in-interest may appear in any contested case. All appearances shall be subject to a motion to strike upon a showing that the party has no justifiable or administratively cognizable interest in the proceeding. An appearance under this section shall be filed at least 15 days in advance of the hearing date and shall include a statement that identifies the party's cognizable interest in the proceeding.

§29.11. Entry of Appearance; Continuance.

(a) The respondent shall enter an appearance within 30 days of the date on which the notice of hearing is provided to the respondent.

(b) For purposes of this section, an entry of appearance means the filing of a written answer or other responsive pleading with SOAH.

(c) For purposes of this section, notice of hearing is provided to a respondent on the date of deposit in the United States mail of a registered or certified letter, return receipt requested, containing the notice of hearing, or if provided by personal service, the date of personal delivery of the notice of hearing.

(d) The failure of a party to timely enter an appearance as provided in this section shall entitle the petitioner to a continuance if so requested.

(e) The notice of hearing shall include the following language in capital letters in at least 10-point boldface type: "YOUR FAILURE TO ENTER AN APPEARANCE BY FILING A WRITTEN ANSWER OR RESPONSE TO THE ALLEGATIONS CONTAINED IN THIS NOTICE WITHIN 30 DAYS OF THE DATE THIS NOTICE WAS MAILED OR PERSONALLY DELIVERED TO YOU SHALL ENTITLE THE DEPARTMENT TO RESCHEDULE THE HEARING OF THIS CASE UNTIL A LATER DATE AS SET BY THE ADMINISTRATIVE LAW JUDGE. ANY COSTS INCURRED IN RESCHEDULING THE HEARING MAY BE ASSESSED AGAINST YOU."

§29.12. Appearances Personally or by Representative.

Any individual may represent himself or herself, or may be represented by an attorney authorized to practice law in the State of Texas, or by a bona fide full-time employee. A corporation, partnership or association may appear and be represented by any bona fide officer, partner or full-time employee. The judge may require any person appearing in a representative capacity to provide such evidence of authority as the judge deems necessary.

§29.13. Sufficiency of Pleadings.

(a) Upon the filing of any pleading, the judge shall examine the same and determine its sufficiency under these rules. If the judge finds that the pleading does not comply in all material respects with these rules, SOAH's rules, or the APA, the judge shall return the pleading to the party who filed it, along with a statement of the reasons for rejecting the same. The party who filed such pleading shall thereafter have the right to file a corrected pleading; provided that the filing of such corrected pleading shall not be permitted to delay any hearing unless the judge shall determine that such delay is necessary in order to prevent injustice or to protect the public interest and welfare.

(b) The judge shall direct all parties to enter their appearances on the record. If exceptions to the form or sufficiency of a pleading have been filed in writing at least three days prior to the date of hearing, they shall be heard; otherwise not. If exceptions are sustained, the judge shall allow a reasonable time for amendment, subject to the provisions of subsection (a) of this section and §29.15 of this title (relating to Trial Amendments).

§29.14. Motions.

Any motion relating to a pending contested case shall, unless made during a hearing, be written, and shall set forth the relief sought and the specific reasons and grounds for the relief. If based upon matters, which do not appear of record, it shall be supported by affidavit. Any motion not made during a hearing shall be filed with the judge, who shall act upon the motion at the earliest practicable time.

§29.15. Trial Amendments.

Any pleading may be amended at any time upon motion. A motion to amend a pleading filed less than seven days prior to the hearing shall be grounds for a continuance unless the amendment(s) would not be an unfair surprise to the non-moving party. However, the pleading upon which notice has been issued shall not be amended so as to broaden the scope of the notice.

§29.16. Incorporation of Department Records by Reference.

Any pleading may adopt and incorporate, by specific reference thereto, any part of any document or entry in the official files and records of the department. This section shall not relieve any party of the necessity of alleging in detail, if required, facts necessary to sustain the burden of proof imposed by law.

§29.17. Consolidation and Severance.

(a) The department may consolidate two or more contested cases if the cases involve common questions of law and fact, and separate hearings would result in unwarranted expense or delay or substantial injustice.

(b) A motion for severance of one or more proceedings shall be in writing, signed by the movant or the movant's attorney or representative, and filed with the judge prior to the date set for hearing. A severance shall not be granted without the affirmative consent of the parties unless the judge finds that a consolidation of two or more proceedings would result in unwarranted expense or delay or substantial injustice to the movant.

§29.18. Informal Disposition.

(a) If the parties reach an agreed settlement which resolves the facts or issues in controversy, further proceedings shall be abated upon a motion. A settlement agreement shall be filed directly with the director or the director's designee for approval. If the director or the director's designee does not approve the agreed settlement, the matter shall proceed as a contested case under this title.

(b) An executed settlement agreement is binding on the respondent and the department according to its terms.

(c) Once a respondent consents to a settlement, the respondent may not withdraw consent pending approval by the director or the director's designee. However, if the director or director's designee has not approved the settlement within 30 days after respondent's consent to the settlement, respondent may withdraw consent.

§29.19. Motions for Continuance Made During the Course of a Hearing.

Once a contested case hearing has been called to order by the judge, no postponement or continuance shall be granted by the judge without the consent of all parties involved.

§29.20. Venue.

All contested case hearings shall be held in Austin, Texas, and shall be open to the public.

§29.21. Transcripts.

(a) Transcripts. Contested case hearings shall be transcribed or tape-recorded. The cost of any transcription may be assessed against the party requesting it and included in the final decision of the director or the director's designee.

(b) Suggested corrections. Suggested corrections to the transcript of the record may be offered within 10 days after the transcript is filed in the contested case, unless the judge shall permit suggested corrections to be offered thereafter. Suggested corrections shall be served in writing upon each party of record, the official reporter, and the judge. If suggested corrections are not objected to, the judge will direct the corrections to be made and the manner of making them. In case the parties disagree on suggested corrections, they may be heard by the judge, who shall then determine the manner in which the record shall be changed, if at all.

§29.22. Rules of Evidence.

In all cases, irrelevant, immaterial, or unduly repetitious evidence shall be excluded. The rules of evidence as applied in non-jury civil cases in the district courts of this state shall be followed. When necessary to ascertain facts not reasonably susceptible of proof under those rules, evidence not admissible thereunder may be admitted if it is of a type commonly relied upon by reasonable persons in the conduct of their affairs. The judge shall give effect to the rules of privilege recognized by law. Objections to evidentiary offers may be made and shall be noted in the record. In order to expedite a hearing, any part of the evidence may be received in written form. An affidavit by a witness, investigator or law enforcement officer or a report of a department employee which has been filed with the department shall be admissible as a public record.

§29.23. Offer of Proof.

When testimony is excluded by ruling of the judge, the party offering such evidence shall be permitted to make an offer of proof by dictating or submitting in writing the substance of the proposed testimony, prior to the conclusion of the hearing, and such offer of proof shall be sufficient to preserve the point for review. The judge may ask such questions of the witness as he or she deems necessary to determine that the witness would testify as represented in the offer of proof. An alleged error in sustaining an objection to questions asked on cross-examination may be preserved without making an offer of proof.

§29.24. Discovery-General.

(a) The scope of discovery in contested case proceedings under this chapter is governed by APA. Responses to requests for admission, written interrogatories, and requests for production that are served with the initial notice of hearing shall be due 30 days from the date notice is received by respondent.

(b) Any time after SOAH acquires jurisdiction, a party may deliver or have delivered to any other party a written request for admissions of facts and genuineness of documents. Requests for admission shall be filed with SOAH at the time they are mailed or personally delivered to the receiving party.

(c) Each matter for which an admission is requested shall be deemed admitted unless, within the time provided, the party to whom the request is directed serves upon the party requesting admissions, a sufficient written answer or objection addressed to each matter of which an admission is requested. An evasive or incomplete answer may be treated as a failure to answer.

(d) If a respondent refuses to admit a matter or the authenticity of a document which is later proved, the petitioner may include its costs incurred in making the proof under §29.29 of this title (relating to Proof of Attorney's Fees, Costs, and Expenses of the Department).

§29.25. Discovery Motions and Sanctions.

(a) Certificate for disputes. All discovery motions concerning a discovery dispute shall contain a certificate by the movant that efforts to resolve the discovery dispute without the necessity of intervention have been attempted and failed.

(b) Compelling discovery. Upon reasonable notice to all party representatives and affected persons, a party may apply to the judge for an order compelling discovery. A party may not request sanctions without first obtaining an order compelling discovery.

(c) Sanctions. If a party fails to comply with proper discovery requests or to obey an order compelling discovery, the judge may, after opportunity for hearing, make orders in response to the failure, including:

(1) disallow any further discovery of any kind or a particular kind for the non-compliant party;

(2) rule that particular facts shall be regarded as established for purposes of the proceeding; or

(3) disallow presentation by the non-compliant party of evidence on issues that were the subject of the discovery request.

(d) Costs. Costs as a discovery sanction may not be imposed except as specifically provided under §29.24(d) of this title (relating to Discovery-General) and §29.29 of this title (relating to Proof of Attorney's Fees, Costs, and Expenses of the Department).

§29.26. Subpoena.

The issuance of subpoenas for witnesses and production of books, records, paper and objects that may be necessary in a proceeding shall be governed by APA, Texas Government Code §2001.089 and §2001.103. The judge shall issue a subpoena upon the written application of any party showing good cause and the deposit of the sums estimated to accrue as provided under APA with SOAH. A party requesting a subpoena shall serve a copy of the application on all other parties. An application for subpoena shall be received by SOAH at least ten days prior to the scheduled hearing.

§29.27. Failure To Attend Hearing; Default Judgment.

(a) If a respondent fails to appear in person or by authorized representative on the day and time set for hearing in the contested case, regardless of whether an appearance has been entered, the judge shall enter a default judgment in the matter adverse to the respondent.

(b) For purposes of this section, default judgment means the issuance of a proposal for decision against the respondent in which the factual allegations against the respondent in the notice of hearing are deemed admitted as true, without any requirement for additional proof to be submitted by the petitioner.

(c) Any default judgment granted under this section will be entered on the basis of the factual allegations contained in the notice of hearing, and upon the proof of proper notice to the defaulting party opponent.

(d) After the granting of a motion for default judgment, a motion by the respondent to reopen the record may be granted if the respondent establishes that the failure to attend the hearing was neither intentional nor the result of conscious indifference.

(1) A motion to reopen the record must be filed with the judge within five (5) days of the date of the hearing. The judge shall only grant the motion to reopen the record upon a showing of good cause for the respondent's failure to attend the hearing.

(2) A motion to reopen the record is not a motion for rehearing and is not to be considered a motion for rehearing. The filing of a motion to reopen has no effect on either the statutory time periods for the filing of a motion for rehearing or on the time period for ruling on a motion for rehearing.

§29.28. Filing of Exceptions, Briefs and Replies.

(a) Any party of record may, within 15 days after the date of service of a proposal for decision, file exceptions and briefs to the proposal for decision, and replies to such exceptions and briefs may be filed within 10 days after the date for filing of such exceptions or briefs.

(b) The points involved in exceptions, briefs, and replies shall be concisely stated. The evidence in support of each point shall be abstracted or summarized, and/or briefly stated in the form of proposed findings of fact. Complete citations to the page number of the record of exhibit referring to evidence shall be made. The specific purpose for which the evidence is relied upon shall be stated. The argument and authorities shall be organized and directed to each point properly proposed as a finding of fact in a concise and logical manner. Briefs shall contain a table of contents and authorities. Prior to the issuance of a proposal for decision, briefs may be filed only when requested or permitted by the judge.

§29.29. Proof of Attorney's Fees, Costs, and Expenses of the Department.

(a) General. If authorized by statute, the department may submit evidence of costs, fees, expenses, and reasonable and necessary attorney's fees incurred by the department. Costs include all expenses incurred by the department in instituting and prosecuting the contested case. Costs specifically include, but are not limited to, investigative costs, witness fees and deposition expenses, travel expenses of witnesses, fees for professional services or expert witnesses, costs of adjudication before SOAH, and any other costs that are necessary for the preparation of the department's case including the cost of any transcriptions, or any other costs specifically provided for by statute.

(b) Submission. The department may submit evidence of costs, fees, expenses, and reasonable and necessary attorney's fees as part of its case-in-chief, by affidavit, or by motion after the issuance of the judge's proposal for decision. Postponement of the introduction of evidence of costs until after the issuance of a proposal for decision shall not constitute a waiver of the department's right to recover any part of its incurred costs.

§29.30. Final Decisions and Orders.

(a) All final decisions and orders shall be in writing and shall be signed by the director or the director's designee.

(b) If the director or the director's designee seeks clarification or additional information relating to the proposal for decision, the director or the director's designee may send written questions, including a request to reopen the hearing if necessary, to the judge with copies to all parties of record.

(c) The director or the director's designee's final decision may adopt the judge's finding, setting out costs, fees, expenses, and reasonable and necessary attorneys' fees incurred by the department in bringing the proceeding.

§29.31. Stay of Enforcement-Motor Carrier.

(a) A party filing an affidavit to stay enforcement of a penalty based on financial inability to give a supersedeas bond shall serve a copy of the affidavit by certified mail on the director or the director's designee. The affidavit shall be mailed to the attorney of record for the department in the contested case.

(b) A supersedeas bond filed under this rule shall be executed by a person authorized to do business in Texas as a surety.

§29.32. Certified Record.

(a) Upon receiving a copy of a petition filed in district court which seeks judicial review of a final decision in a contested case decided under this title, the department shall prepare a certified copy of the entire record of the proceeding under review, and transmit it to the reviewing court.

(b) Pursuant to APA §2001.177, a party seeking judicial review of the final decision of the director or the director's designee in a contested case shall pay all costs of preparing a record of the contested case proceedings.

§29.33. Conflicts.

If there is a conflict between SOAH's rules of procedure and these rules of procedure, these rules shall control. If there is conflict between these rules and the applicable statutes, the statutes shall control.

§29.34. Effective Date.

These sections shall govern all proceedings filed after they take effect, and they also govern all proceedings then pending, and except to the extent that the director or the director's designee shall determine that their application in a particular pending proceeding would not be feasible or would work injustice, in which event the former procedure applies.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 22, 1999.

TRD-9908989
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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Chapter 31. STANDARDS FOR AN APPROVED MOTORCYCLE OPERATOR TRAINING COURSE

37 TAC §§31.1, 31.4, 31.6, 31.9-31.11

The Texas Department of Public Safety proposes amendments to §§31.1, 31.4, 31.6, and 31.9-31.11, concerning Motorcycle Operator Training Course. Amendment to §31.1 is necessary due to a reorganization within the department wherein the Motorcycle Safety Bureau was renamed the Motorcycle Safety Unit. Amendment to §31.4(b) is necessary to reflect that a student who is 15 years old but is less than 18 years old and who presents an instructional permit or unrestricted provisional Class C or higher driver license is qualified to take the basic motorcycle operator training course. Amendment to §31.6(1) adds language which clarifies the instructional requirements for the basic course, as well, as providing additional grounds for de-certification of instructors who fail to comply with these requirements. Section 31.9 and §31.10 are amended to comport with the language of Texas Transportation Code, §662.004 which defines the Motorcycle Safety Coordinator's duties and the program's new title established as the result of the reorganization. Amendment to §31.11 is also necessary due to the reorganization.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the rule is in effect there will be no fiscal implications to state or local government.

Mr. Haas also has determined that for each year of the first five year period the rules are in effect the public benefit anticipated as a result of enforcing the rules will be clarification of existing rules. There is no anticipated economic cost to individuals. There is no anticipated economic cost to small or large businesses.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The amendments are proposed pursuant to Texas Government Code, §411.004(3), which authorizes the commission to adopt rules considered necessary for carrying out the department's work and Texas Transportation Code, §662.009.

Texas Government Code, §411.004(3) and Texas Transportation Code, §662.009 are affected by this proposal.

§31.1. Definitions.

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1)-(6) (No change.)

(7) Motorcycle Safety Unit [~~Bureau~~]–An administrative unit [~~bureau~~] within the department assigned with the responsibility for establishing and administering the motorcycle operator training and safety program.

(8)-(9) (No change.)

§31.4. Student Admission Requirements.

(a) (No change.)

(b) A person who is 15 years old but is less than 18 years old may not be admitted to a basic motorcycle operator training course unless he or she has a Class C instructional permit [~~before providing proof of successful completion of the first six hours of the driver education course as required by the Texas Education Agency. Proof of successful completion of the classroom driver education requirement is a properly annotated Texas Driver Education Certificate, form DE-964(E). An instruction permit for a Class C, or higher, driver license~~] or an unrestricted Class C, or higher, driver license[~~is considered proof of completion of the driver education requirement~~].

(c) (No change.)

§31.6. Approved Motorcycle Training Courses.

(a) Except as modified by subsection (c) of this section, the department adopts the educational, safety, and instructor standards, by reference, of the most current versions of the following Motorcycle Safety Foundation (MSF) courses:

(1) the approved basic motorcycle operator training course is the Motorcycle RiderCourse: Riding and Street Skills (MRC:RSS), Modules 1 through 15 and Exercise 22. Instructors shall adhere to the MSF's Evaluation, Coaching and Range Management - Instructor Guide requirements when conducting all range exercises;

(2) the approved advanced motorcycle operator training courses are the Experienced RiderCourse (ERC) and the Optional Experienced RiderCourse. The choice of curricula is determined by the size of the riding area. The skill and knowledge tests for either curricula are not required but may be used at the sponsor's discretion; and

(3) the approved instructor preparation course is the MSF instructor preparation course curriculum.

(b)-(d) (No change.)

§31.9. Suspension.

The term of suspension under §31.2 of this title (relating to Program Sponsor) and §31.3 of this title (relating to Motorcycle Instructor) may not exceed one year. The term of suspension may be reduced by the coordinator [~~manager of the~~] Motorcycle Safety Unit [~~Bureau~~] if corrective actions have been taken and the reason for suspension no longer exists. If the reason for suspension still exists at the end of the suspension period, the suspension automatically elevates to [~~the~~]cancellation of approval. To regain approval, a [~~disapproved~~]sponsor or instructor whose approval has been canceled must reapply and meet all current requirements for approval.

§31.10. Quality Assurance Visits.

(a)-(b) (No change.)

(c) While conducting the QAV, the evaluator will use the same pass/fail criteria as is utilized to evaluate the student teaching portion of the approved motorcycle safety instructor training course. Instructor(s) not meeting the requirements of the approved criteria will be suspended as outlined in §31.3 of this title (relating to Motorcycle Instructor). Remedial actions necessary to remove the suspension will be determined by the [~~manager of the~~]Motorcycle Safety coordinator [~~Bureau~~] and may include, but is not limited to:

(1) attending a department-sponsored instructor curriculum refresher course;

(2) attending all or portions of a department-sponsored instructor training course; or

(3) teaching an entire course under the supervision of a Motorcycle Safety Unit [~~Bureau~~] staff member, an approved chief instructor, or other individual expressly designated by the department to perform such duties.

§31.11. Notification of Legal Actions.

All sponsors shall notify the Motorcycle Safety Unit [~~Bureau~~] with the details of any legal action which has been filed against the sponsor, its officers, or its contracted instructors within 30 days of such action.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908990
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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Chapter 32. BICYCLE SAFETY AND EDUCATION PROGRAM

37 TAC §32.2

The Texas Department of Public Safety proposes an amendment to §32.2, concerning Bicycle Safety Curriculum. Subsection (c) is amended to indicate the department bureau responsible for the SuperCyclist Bicycle Safety Course.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the rule is in effect there will be no fiscal implications to state or local government.

Mr. Haas also has determined that for each year of the first five years the rule is in effect the public benefit anticipated as a result of enforcing the rule will be the enhancement of bicycle safety behaviors by children and adults as a result of completing and teaching the SuperCyclist course. There is no anticipated economic cost to individuals. There is no anticipated economic cost to small or large businesses.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The amendment is proposed pursuant to Texas Government Code, §411.004(3), which authorizes the Public Safety Commission to adopt rules considered necessary for carrying out the department's work and Health and Safety Code, Chapter 758 which provides that a licensed provider may contract with instructors and may subsequently issue completion certificates to those students who successfully complete the course.

Texas Government Code, §411.004(3) and Health and Safety Code, Chapter 758 are affected by this proposal.

§32.2. Bicycle Safety Curriculum.

(a)-(b) (No change.)

(c) The SuperCyclist Bicycle Safety Course is available for inspection at the Department's Austin Headquarters, in the custody of the Training[~~Motorcycle Safety~~] Bureau, Bicycle Safety Coordinator.

(d)-(i) (No change.)

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908988
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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Chapter 33. ALL-TERRAIN VEHICLE OPERATOR EDUCATION AND CERTIFICATION PROGRAM

37 TAC §§33.1-33.5

The Texas Department of Public Safety proposes amendments to §§33.1 - 33.5, concerning All-terrain Vehicle Operator Education and Certification Program. Amendment to §33.1 deletes paragraph (3) from the definitions section as this decree is no longer in effect due to having expired in April, 1998. Paragraphs (4) - (8) are renumbered as (3) - (7). Section 33.2 is amended to delete reference to the decree which has expired and also deletes reference to "seven-hours" concerning the All-Terrain Vehicle (ATV) Safety Institute's RiderCourse which may vary in length, and over which the department has no control. Amendment further reflects the change in zip code for the ATV Safety Institute, as well as a change of name due to reorganization within the department. Section 33.3 is also amended to delete reference to the decree. Amendment to §33.4 reflects the recodification of certain provisions of Texas Civil Statutes to Texas Transportation Code and Occupations Code. Subsection (g) is amended to reflect the proper method for waiver of an administrative hearing. Section 33.5 is amended to provide that the department will issue its course completion certificate within 30 days after the department actually receives the necessary information from the ATV Safety Institute. This change is necessary because the department has no control over when the ATV Safety Institute will forward completion information from their approved courses. Subsection (c) is also deleted and remaining subsections are renumbered.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the rules are in effect there will be no fiscal implications for state or local government.

Mr. Haas also has determined that for each year of the first five years the rules are in effect the public benefit anticipated as a result of enforcing the rules will be current and updated department rules. There is no anticipated economic cost to individuals. There is no anticipated economic cost to small or large businesses.

Comments on the proposal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The amendments are proposed pursuant to Texas Government Code, §411.004(3), which authorizes the commission to adopt rules considered necessary for carrying out the department's work and Texas Transportation Code, §663.018, which states that the "designated division or state agency may adopt rules to administer this chapter." The Governor has designated the Texas Department of Public Safety to administer the all-terrain vehicle operator education and certification program as provided by Texas Transportation Code, §663.011.

Texas Government Code, §411.004(3) and Texas Transportation Code, §663.018 and §663.011 are affected by this proposal.

§33.1. Definitions.

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise.

(1) All-terrain vehicle (ATV)–A motor vehicle having a saddle for the use of the rider, designed to propel itself with three or four tires in contact with the ground, designed by the manufacturer for off-highway use by the operator only and not designed by the manufacturer for farming or lawn care.

(2) All-terrain Vehicle Safety Institute (ASI)–A not-for-profit operating division of the Specialty Vehicle Institute of America (SVIA), which was formed in 1988 to implement an expanded national program of ATV safety education and awareness. SVIA was founded in 1983 by the four leading United States distributors of all-terrain vehicles to promote the safe and responsible use of speciality vehicles.

[~~(3) Consent decree–Final consent decree filed April 28, 1988, between major ATV manufacturers and the United States Department of Justice and approved by the United States District Court, District of Columbia, in Civil Action Number 87-3525 GAG. The consent decree outlines requirements for the ATV manufacturers to address the safety concerns of the Consumer Product Safety Commission to reduce ATV-related deaths and injuries. The consent decree established the administrative framework for ATV safety training.~~]

(3) [~~(4)~~] Department–Texas Department of Public Safety.

(4) [~~(5)~~] Director–The executive director of the Texas Department of Public Safety.

(5) [~~(6)~~] Program–The ATV Operator Education and Certification Program providing basic training and safety skills for ATV operation.

(6) [~~(7)~~] Program sponsor–The entities with which the Department of Public Safety enters into an agreement to administer the ATV Operator Education and Certification Program.

(7) [~~(8)~~] Public property–Property owned or leased by the State of Texas or a political subdivision of the state.

§33.2. Operator Education Program.

(a) The all-terrain vehicle (ATV) operator education course curriculum shall consist of the Texas Department of Public Safety's approved training program and the distribution of information about Texas laws which pertain to ATVs. The department approves and adopts the most current version of the ATV Safety Institute's [~~seven-hour~~]hands-on ATV RiderCourse [~~ridercourse which meets the requirements set forth in the consent decree~~].

(b) Copies of the course curriculum may be obtained from the ATV Safety Institute, Education Department, 2 Jenner Street, Suite 150, Irvine, California 92618-3806 [~~92718~~]. The course curriculum may be reviewed at Texas Department of Public Safety Headquarters, Motorcycle Safety Unit [~~Bureau~~], 5805 North Lamar Boulevard, Austin.

(c) Classes attended by children under age 16 shall be modified for class size and composition according to the most current standards set out by the ATV Safety Institute.

(d) All all-terrain vehicles used for training shall be no greater than the recommended size for the individual in accordance with the age/size [~~age~~] recommendations of the ATV manufacturer [~~contained in the consent decree~~].

(e) A parent or guardian of children under the age of 18 must provide his or her signed written consent granting his or her permission for the child to participate as a student in the course on a form which includes the [~~Consumer Product Safety Commission injury and accident statistics and the~~] appropriate age recommendations for ATVs consistent with the age recommendations listed in the most current ATV Safety Institute Instructor Guide [~~contained in the consent decree.~~]

(f) The course will be offered at no charge to all persons and members of their immediate families who have purchased a new ATV since December 30, 1986; provided, however, that such persons meet the minimum age required for the vehicle purchased. A fee of not more than $35 or the amount approved by the department, whichever is more, may be charged other persons. The program sponsor will be notified of the amount approved by the department if the fee is modified.

(g) The course locations will be determined by the program sponsor based, in part, upon the quantity of ATV training requests [~~in accordance with the consent decree~~].

§33.3. Operator Education Program Sponsor and Instructors.

(a) The department will enter into an agreement with the All-Terrain Vehicle Safety Institute (ASI), which represents the manufacturers, [~~who must conform to the requirements which have been mandated in the consent decree~~] to operate the training program, to serve as program sponsor, to administer the program, and to train instructors.

(b) The department approves and adopts the most current version of the ASI's instructor preparation curriculum and standards as identified in the most current edition of the ATV Safety Institute ATV RiderCourse Chief Instructor's Guide.

(c) Upon written application to the department, persons who successfully complete the approved all-terrain vehicle instructor preparation course, enter into an instructor license agreement with ASI, and meet the minimum qualifications as contained in these rules will be approved to teach the course in Texas for the period stated in their license.

§33.4. Notice of Hearing Requirements.

(a) The department may deny, suspend, or cancel its approval for a program sponsor to conduct a course or for an instructor to teach courses offered under this chapter if the applicant, instructor, or program sponsor:

(1) does not meet the requirements established under Texas Transportation Code, Chapter 663 [~~Civil Statutes, Article 6701c-5~~], to receive or retain approval;

(2) permits fraud or engages in any fraudulent practices with reference to an application to the department, induces or countenances fraud or fraudulent practices on the part of any application for a driver's license or permit, or permits or engages in any other fraudulent practice in any action between the applicant or licensee or the public;

(3) does not comply with the rules and regulations of the department; or

(4) is convicted under the laws of this state, another state, or the United States, of any felony or offense involving moral turpitude, tampering with a governmental record, driving while intoxicated or driving under the influence of drugs, or an offense committed as a result of the person's criminally negligent operation of a motor vehicle:

(A) these particular crimes relate to the conducting and teaching courses because the program sponsor and instructors are required to be of good reputation, character, moral conduct, and to deal honestly with members of the public. Program sponsors and instructors are required to keep records on behalf of the department and are required to recognize the importance of, encourage, and practice safe driving techniques;

(B) a conviction for an offense other than a felony will not be considered by the department, under this paragraph, if a period of more than five years has elapsed since the date of the conviction or of the release of the person from the confinement or supervision imposed for that conviction, whichever is the later date. For the purposes of this section, a person is convicted of an offense when an adjudication of guilt on an offense is entered against the person by a court of competent jurisdiction, whether or not:

(i) the sentence is subsequently probated and the person is discharged from probation;

(ii) the accusation, complaint, information, or indictment against the person is dismissed and the person is released from all penalties and disabilities resulting from the offense; or the person is pardoned for the offense, unless the pardon is expressly granted for subsequent proof of innocence;

(C) in determining the present fitness of a person who has been convicted of a crime and in determining whether a criminal conviction directly relates to an occupation, the department shall consider those factors stated in Occupations Code, Chapter 53 [~~Texas Civil Statutes, Article 6252-13c and Article 6252-13d~~];

(5) does not enter into any license agreement required by these rules or any such agreement is revoked, transferred, assigned, or is subject to revocation because of the actions of the applicant or instructor.

(b) When there is cause to deny, suspend, or cancel the approval of a program sponsor or instructor, the director shall, no less than 30 days before refusal, suspension, or revocation action is taken, notify the person in writing, in person, or by certified mail at the last address supplied to the department, of the impending refusal, suspension, or revocation, the reasons for taking this action, the effective date of the action, and of his/her right to an administrative hearing for the purpose of determining whether or not the evidence is sufficient to warrant the refusal, suspension, or revocation action proposed to be taken by the director.

(c) The director, without a hearing, may suspend, revoke, or refuse to issue approval for a program sponsor to conduct a course or for an instructor to teach courses if, within 20 days after actual notice or the notice has been deposited in the United States mail, the person has not made a written request to the director for this administrative hearing.

(d) On receipt by the director of a written request for an administrative hearing within the 20-day period, an opportunity for an administrative hearing shall be afforded as early as is practicable.

(e) The administrative hearing shall be before the director or his designee.

(f) On the basis of the evidence submitted at the hearing, the director, acting for himself or upon the recommendation of his designee, may refuse or revoke the approval.

(g) A program sponsor or instructor may waive the right to an administrative hearing in writing by completing the Voluntary Waiver of Administrative Hearing form that accompanies the department's notice of intent to suspend, revoke, or refuse to approve a program sponsor or instructor [~~Form MSB-ATV1, Voluntary Waiver of Administrative Hearing.~~]

(h) The procedure of the administrative hearing shall comply with §§29.1-29.49 of this title (relating to Practice and Procedure), except where otherwise provided.

§33.5. Operator Certification Requirements.

(a) The program sponsor will provide names to the department, in a format which meets the department's approval, of all persons who successfully complete the course no later than 45 days after the date of completion of the course.

(b) The department shall issue an all-terrain vehicle safety course completion certificate within 30 days of receiving verification of course completion from the ATV Safety Institute [~~75 days of the date of completion of the course to persons the instructor determines have successfully met the minimum standard and completed the approved course~~]. The All-terrain Vehicle Safety Institute (ASI) completion card[~~,~~] issued by the instructor immediately following completion of the class, shall serve as a temporary completion certificate to meet the requirements for operation on public land until the student receives the department's completion certificate [~~for 75 days after the date of completion of the course~~].

[~~(c) Upon proof that a person has completed an ASI approved course between January 1, 1988, and the adoption of this chapter, the department shall issue a safety course completion certificate. Said certificate will be issued within 90 days of the adoption of this chapter. Acceptable proof will be written documentation from ASI indicating the person's name, address, and date of class.~~]

(c) [~~(d)~~] A person who resides in a county in which the course is not being offered is exempted from the requirement to hold a safety certificate for operation on public land while operating the all-terrain vehicle in that county until such times as the course is available in that county.

(d) [~~(e)~~] If an all-terrain vehicle safety certificate is lost, mutilated, or destroyed, the department will issue a duplicate certificate. The person to whom the certificate was issued must make a request for a duplicate certificate in writing to the department including his or her name, address, and date of class. There is no fee required.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908979
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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37 TAC §33.6

(Editor's note: The text of the following section proposed for repeal will not be published. The section may be examined in the offices of the Texas Department of Public Safety or in the Texas Register office, Room 245, James Earl Rudder Building, 1019 Brazos Street, Austin.)

The Texas Department of Public Safety proposes the repeal of §33.6, concerning Consumer Product Safety Commission. The section is repealed due to the consent decree having expired.

Tom Haas, Chief of Finance, has determined that for each year of the first five-year period the repeal is in effect there will be no fiscal implications to state or local government.

Mr. Haas also has determined that for each year of the first five-year period the repeal is in effect the public benefit anticipated as a result of enforcing the repeal will be the removal of obsolete rules. There is no anticipated economic cost to individuals or small or large businesses.

Comments on the repeal may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

The repeal is proposed pursuant to Texas Government Code, §411.004(3) which authorizes the commission to adopt rules considered necessary for carrying out the department's work and Texas Transportation Code, §663.018, which states that the "designated division or state agency may adopt rules to administer this chapter." The Governor has designated the Texas Department of Public Safety to administer the All-Terrain Vehicle Operator Education and Certification Program as provided by Texas Transportation Code, §663.011.

Texas Government Code, §411.004(3) and Texas Transportation Code, §663.018 and §663.011 are affected by this proposal.

§33.6. Consumer Product Safety Commission.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908985
Dudley M. Thomas
Director
Texas Department of Public Safety
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-2135

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TITLE 40. SOCIAL SERVICES AND ASSISTANCE

Part 2. TEXAS REHABILITATION COMMISSION

Chapter 106. CONTRACT ADMINISTRATION

Subchapter F. RESOLUTION OF CERTAIN CONTRACT CLAIMS AGAINST THE STATE–NEGOTIATION OF CLAIM

40 TAC §§106.55 - 106.60

The Texas Rehabilitation Commission (TRC) proposes a new Subchapter F, §§106.55-106.60, concerning resolution of certain contract claims against the state–negotiation of claim.

The new sections are proposed to implement the provisions of the Government Code, Chapter 2260.

Charles E. Harrison, Jr., Deputy Commissioner for Financial Services, has determined that for the first five-year period the sections are in effect, there will be no fiscal implications for state or local government.

Mr. Harrison also has determined that for each year of the first five years the sections are in effect the public benefit anticipated as a result of enforcing the sections will be the enforcement of new rules regarding resolution of certain contract claims against the state. There will be no effect on small businesses. There is no anticipated economic cost to persons who are required to comply with the sections as proposed.

Comments on the proposal may be submitted to Roger Darley, Assistant General Counsel, Texas Rehabilitation Commission, 4900 North Lamar Boulevard, Suite 7300, Austin, Texas 78751.

The new sections are proposed under the Texas Human Resources Code, Title 7, Chapter 111, §111.018 and §111.023, which provides the Texas Rehabilitation Commission with the authority to promulgate rules consistent with Title 7, Texas Human Resources Code.

No other statute, article, or code is affected by this proposal.

§106.55. Claim for Breach of Contract; Notice.

(a) In accordance with Government Code, Chapter 2260, Subchapter B, a contractor may make a claim against the commission for breach of a contract between the commission and the contractor. The commission may assert a counterclaim against the contractor.

(b) A contractor must provide written notice to the commission of a claim for breach of contract not later than the 180th day after the date of the event giving rise to the claim.

(c) The notice must state with particularity:

(1) the nature of the alleged breach;

(2) the amount the contractor seeks as damages; and

(3) the legal theory of recovery.

(d) The commission must assert, in a writing delivered to the contractor, any counterclaim not later than the 90th day after the date of notice under this subsection. If the commission does not comply with this subsection it waives the right to assert the counterclaim.

§106.56. Negotiation.

(a) The Associate Commissioner for buyer Support Services shall examine the claim and any counterclaim and negotiate with the contractor in an effort to resolve them. Except as provided by subsection (b) of this section, the negotiation must begin not later than the 60th day after the later of:

(1) the date of termination of the contract;

(2) the completion date in the original contract; or

(3) the date the claim is received.

(b) The commission is entitled to delay the beginning of negotiation until after the 180th day after the date of the event giving rise to the claim.

§106.57. Partial Resolution of Claim.

(a) If the negotiation under §106.56 of this title (relating to Negotiation) results in the resolution of some disputed issues by agreement or in a settlement, the parties shall reduce the agreement or settlement to writing and each party shall sign the agreement or settlement.

(b) A partial settlement or resolution of a claim does not waive a party's rights under this chapter as to the parts of the claim that are not resolved.

§106.58. Payment of Claim from Appropriated funds.

The commission may pay a claim resolved in accordance with this subchapter only from money appropriated to it for payment of contract claims or for payment of the contract that is the subject of the claim. If money previously appropriated for payment of contract claims or payment of the contract is insufficient to pay the claim or settlement, the balance of the claim may be paid only from money appropriated by the legislature for payment of the claim.

§106.59. Incomplete Resolution.

If a claim is not entirely resolved under §106.56 of this title (relating to Negotiation) on or before the 270th day after the date the claim is filed with the commission, unless the parties agree in writing to an extension of time, the contractor may file a request for a hearing under Government Code, Chapter 2260, Subchapter C.

§106.60. Mediation.

(a) Before the 270th day after the date the claim is filed with the commission and before the expiration of any extension of time under §106.59 of this title (relating to Incomplete Resolution), the parties may agree to mediate the claim made under this subchapter.

(b) Participation in mediation shall be voluntary on the part of the commission and the contractor.

This agency hereby certifies that the proposal has been reviewed by legal counsel and found to be within the agency's legal authority to adopt.

Filed with the Office of the Secretary of State, on December 27, 1999.

TRD-9909040
Charles Schiesser
Chief of Staff
Texas Rehabilitation Commission
Earliest possible date of adoption: February 6, 2000
For further information, please call: (512) 424-4050

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WITHDRAWN RULES

An agency may withdraw a proposed action or the remaining effectiveness of an emergency action by filing a notice of withdrawal with the ***Texas Register***. The notice is effective immediately upon filling or 20 days after filing as specified by the agency withdrawing the action. If a proposal is not adopted or withdrawn within six months of the date of publication in the ***Texas Register***, it will automatically be withdrawn by the office of the Texas Register and a notice of the withdrawal will appear in the ***Texas Register.***

TITLE 30. ENVIRONMENTAL QUALITY

Part 1. TEXAS NATURAL RESOURCE CONSERVATION COMMISSION

Chapter 116. CONTROL OF AIR POLLUTION BY PERMITS FOR NEW CONSTRUCTION OR MODIFICATION

Subchapter I. ELECTRIC GENERATING FACILITY PERMITS

30 TAC §116.915

The Texas Natural Resource Conservation Commission has withdrawn from consideration for permanent adoption new §116.915, which appeared in the September 10, 1999, issue of the *Texas Register* (24 TexReg 7163).

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9909017
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: December 22, 1999
For further information, please call: (512) 239-1966

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ADOPTED RULES

An agency may take final action on a section 30 days after a proposal has been published in the ***Texas Register***. The section becomes effective 20 days after the agency files the correct document with the ***Texas Register***, unless a later date is specified or unless a federal statute or regulation requires implementation of the action on shorter notice.

If an agency adopts the section without any changes to the proposed text, only the preamble of the notice and statement of legal authority will be published. If an agency adopts the section with changes to the proposed text, the proposal will be republished with the changes.

TITLE 4. AGRICULTURE

Part 2. TEXAS ANIMAL HEALTH COMMISSION

Chapter 35. BRUCELLOSIS

Subchapter A. ERADICATION OF BRUCELLOSIS IN CATTLE

4 TAC §35.2

The Texas Animal Health Commission (commission) adopts an amendment to §35.2 concerning the Eradication of Brucellosis in Cattle, without changes to the proposed text as published in the October 8, 1999, issue of the *Texas Register* (24 TexReg 8673) and will not be republished.

The requirement to restrict bulls under 18 months of age in infected quarantined herds will bring commission regulations into conformity with the UM&R and will reduce the risk of allowing an infected animal from moving out of a quarantined herd.

No comments were received regarding adoption of the amendment.

The amendment is adopted under the Texas Agriculture Code, Chapter 161, §161.041(a) and (b), and §161.046 which authorizes the Commission to promulgate rules in accordance with the Texas Agriculture Code. Also Chapter 163 of the Agriculture Code furnishes in §163.064 that the commission may provide rules prescribing criteria for the classification of cattle for the purpose of brucellosis testing.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 23, 1999.

TRD-9909034
Gene Snelson
General Counsel
Texas Animal Health Commission
Effective date: January 12, 2000
Proposal publication date: October 8, 1999
For further information, please call: (512) 719-0714

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Chapter 45. REPORTABLE DISEASES

4 TAC §45.1, §45.2

The Texas Animal Health Commission (TAHC) adopts a new Chapter 45 concerning Reportable Diseases with changes to the proposed text as published in the August 13, 1999, issue of the *Texas Register* (24 TexReg 6158). The commission did receive two comments on the proposal and in response to the comments has made some additions to provide greater clarity for veterinarians. Section 45.2 will be republished to indicate this change. Section 45.1 is adopted without changes and will not be republished.

One comment, from the Texas Veterinary Medical Association, was in regards to what constitutes the existence of a disease? The commission believes that the presence of a disease would be determined through a professional veterinarian's study of the signs as well as appropriate clinical or laboratory support. The commission recognizes that the confirmed existence of a disease that may not be commonly seen by the veterinary practitioner is not an easily defined task. The reason for the reporting requirement is to ensure that if there is an outbreak of any of the listed diseases, the commission will be able to respond quickly to ensure that the disease has minimal impact on other livestock in the area and in the state.

The other comment was for the purpose of clarity and in order to give veterinarians better guidance that the names of the causative agent should be listed beside each disease. The commission concurs that by adding the causative agent next to the reportable disease will benefit the veterinarians and makes that addition. The reporting requirement for these diseases is only effective until the last day of the 77th Texas legislative session and an asterisk is added to aid the veterinary practitioner with this distinction.

House Bill (HB) 1244 was passed by the 76th Texas Legislative Session and contains requirements related to the duty of a veterinarian to report specified animal health diseases. This requirement amends the Texas Agriculture Code Chapter 161, §161.101. The section, prior to HB 1244, required a veterinarian to report to the commission the existence of any diseases specified by the statute. HB 1244 is amending that section to repeal the existing list of diseases and authorizing the commission to promulgate rules to specify those diseases. The commission would note that in accordance with HB 1244 the following diseases are ones which the commission has determined are to be reportable because it is necessary for the protection of animal health in this state: Anthrax (multiple Species disease); Scabies (Cattle): Chronic Wasting Disease (Cervidae); Scabies (Sheep); Equine Encephalomyelitis (Horses); Equine Infectious Anemia (Horses); Avian Influenza (List A) (Poultry); Avian Infectious Laryngotracheitis (Poultry); Avian tuberculosis (Poultry); Duck virus hepatitis (Poultry); Duck virus enteritis (Poultry) Infectious encephalomyelitis (Poultry); Ornithosis (Poultry); and Paramyxovirus infections (Poultry). These diseases are being adopted because reporting of these diseases are necessary in order to be protective of animal health in Texas. For these specific diseases the rule will only be effective through the last day of the 77th Texas legislative session unless the rule is continued in effect by act of the legislature. These diseases are denoted by an asterisk. The Section of HB 1244 which authorizes the commission to specify the specific disease will not take effect until January 1, 2000. Any diseases adopted by the commission as being reportable will not become effective until after January 1, 2000.

The new sections are adopted under the Texas Agriculture Code, Chapter 161, §161.041(a) and (b), and §161.046 which authorizes the Commission to promulgate rules in accordance with the Texas Agriculture Code. HB 1244, from the 76th Texas Legislative Session, provides in Sections 2 and Section 6 (b) that the commission has the authority to promulgate such a rule. This piece of legislation is codified in §161.101.

§45.2. Duty To Report.

(a) A veterinarian shall report the existence of the following diseases among livestock, exotic livestock, domestic fowl, or exotic fowl to the commission within 24 hours after diagnosis. The following listing includes diseases and conditions that are Office International Des Epizooties List A Diseases, Foreign Animal Diseases, National Program Diseases or Texas Animal Health Commission Designated Diseases.
Figure: 4 TAC §45.2(a)

(b) In addition to reporting the existence of a disease under subsection (a), the veterinarian shall also report to the commission information relating to:

(1) the species and number of animals involved;

(2) any clinical diagnosis or postmortem findings;

(3) any death losses;

(4) location; and

(5) owner.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 23, 1999.

TRD-9909035
Gene Snelson
General Counsel
Texas Animal Health Commission
Effective date: January 12, 2000
Proposal publication date: August 13, 1999
For further information, please call: (512) 719-0714

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Chapter 55. SWINE

The Texas Animal Health Commission (commission) adopts the repeal and replacement of §55.3, concerning Feeding of Garbage to Swine, without changes to the proposed text as published in the October 8, 1999, issue of the *Texas Register* (24 TexReg 8674) and will not be republished. New §55.3 contains requirements for facilities which feed garbage to swine.

House Bill (HB) 1244 was passed by the 76th Texas Legislative Session and contains requirements related to Feeding Garbage to Swine. This legislation amends the Texas Agriculture Code Chapter 165, §165.026(b). The legislation provides greater specificity as to what the registration should address for requirements as well as to provide the commission authority to assess a fee for the registration. The legislation requires the commission to adopt rules regarding the registration of persons who feed garbage to swine and to provide requirements related to disease tests, inspections and bookkeeping. The purpose of the rule is to insure that this type of facility has the adequate mechanisms in place to prevent the introduction and spread of swine diseases.

The commission is to repeal the previous regulations in order to more clearly indicate the applicable requirements through the rules being proposed. The adopted rules will provide for a number of requirements which are for the purpose of insuring that these facilities have the necessary mechanisms in place to prevent the introduction and spread of diseases in swine. A summary of those requirements are: 1.) prohibiting feeding of feral swine at registered garbage feeding locations; 2.) ability of TAHC to require a brucellosis and pseudorabies negative test prior to issuance of a permit; 3.) annual surveys to be conducted by a commission representative to determine disease risk on each registered location; and 4.) sanitation requirements for water.

HB 1244 provides that the commission may assess a registration fee; however, the commission has determined that in order to insure compliance and in order to not put undue hardship on these facilities, a fee will not be assessed. The rule will become effective after adoption by the commission on February 1, 2000, in order to allow all facilities to become compliant with the requirements.

No comments were received regarding adoption of the rules.

4 TAC §55.3

The repeal is adopted under the Texas Agriculture Code, Chapter 161, §161.041(a) and (b), and §161.046 which authorizes the commission to promulgate rules in accordance with the Texas Agriculture Code. HB 1244, from the 76th Texas Legislative Session, provides in Section 4 that the commission has the authority to promulgate rules to register facilities that feed garbage to swine. This authority is codified in Chapter 165, §165.026(b). Also, §165.022, entitled "Method Of Disease Eradication" provides that the commission shall adopt rules which are to further the purpose of eradicating swine disease.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 23, 1999.

TRD-9909036
Gene Snelson
General Counsel
Texas Animal Health Commission
Effective date: January 12, 2000
Proposal publication date: October 8, 1999
For further information, please call: (512) 719-0714

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The new section is adopted under the Texas Agriculture Code, Chapter 161, §161.041(a) and (b), and §161.046 which authorizes the commission to promulgate rules in accordance with the Texas Agriculture Code. HB 1244, from the 76th Texas Legislative Session, provides in Section 4 that the commission has the authority to promulgate rules to register facilities that feed garbage to swine. This authority is codified in Chapter 165, §165.026(b). Also, §165.022, entitled "Method Of Disease Eradication" provides that the commission shall adopt rules which are to further the purpose of eradicating swine disease

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 23, 1999.

TRD-9909037
Gene Snelson
General Counsel
Texas Animal Health Commission
Effective date: January 12, 2000
Proposal publication date: October 8, 1999
For further information, please call: (512) 719-0714

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Chapter 60. SCRAPIE

4 TAC §60.3

The Texas Animal Health Commission (commission) adopts a new section to Chapter 60, concerning Scrapie. The proposal was published in the October 8, 1999, issue of the *Texas Register* (24 TexReg 8676) and will not be republished. This creates a new §60.3, which provides procedures for indemnity of animals with a high risk of having the disease Scrapie.

House Bill (HB) 1244 was passed by the 76th Texas Legislative Session and provides the commission authority related to compensation to livestock owners for diseased or exposed livestock. This legislation amends the Texas Agriculture Code Chapter 161 by adding §161.058. The commission may pay an indemnity to the owner of livestock exposed to or infected with a disease if the commission considers it necessary to eradicate the disease and to dispose of the exposed or diseased livestock. Scrapie is a fatal, degenerative disease affecting the central nervous system of sheep, goats, and mouflon. It is one of a group of diseases known as Transmissible Spongiform Encephalopathies (TSE). The causative agent is unknown. Other TSE diseases are Mad Cow disease in cattle and Creutzfeldt-Jakob disease in humans. All the TSE diseases are 100% fatal. Scrapie was first seen more than 250 years ago in Great Britain. It is world wide with the exception of Australia and New Zealand. Since 1947 we have diagnosed about 850 flocks with Scrapie in the U.S.

The commission has experienced some difficulty in locating and disposing of high risk animals to slaughter. In order to effectively control this disease in Texas, the commission deems compensation as necessary. The number of high risk animals has been very small to date and the commission believes by indemnifying producers for these animals we will improve disposal of these high risk animals which will enhance Scrapie control and promote eradication of the disease through proper disposal.

No comments were received regarding adoption of the new section.

The new section is adopted under the Texas Agriculture Code, Chapter 161, §161.041(a) and (b), and §161.046 which authorizes the Commission to promulgate rules in accordance with the Texas Agriculture Code. HB 1244, from the 76th Texas Legislative Session, provides in Section 1 that the commission has the authority to pay an indemnity to the owner of livestock exposed to or infected with a disease and the authority to promulgate rules to implement that authority. This authority is found in the Texas Agricultural Code Chapter 161, §161.058.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 23, 1999.

TRD-9909038
Gene Snelson
General Counsel
Texas Animal Health Commission
Effective date: January 12, 2000
Proposal publication date: October 8, 1999
For further information, please call: (512) 719-0714

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TITLE 16. ECONOMIC REGULATION

Part 1. RAILROAD COMMISSION OF TEXAS

Chapter 3. OIL AND GAS DIVISION

16 TAC §3.52, §3.53

The Railroad Commission of Texas adopts the amendments to §3.52, regarding oil well allowable production and to §3.53, regarding annual well tests and well status reports without changes to the versions as published in the October 22, 1999, issue of the *Texas Register* (24 TexReg 9134). The adopted amendments to §§3.52 and 3.53 reduce the regulatory burden on oil and gas wells and reduce operating costs for industry by reducing well testing and reporting requirements.

The proposal published October 22, 1999, also contained proposed amendments to §3.26, regarding separating devices, tanks, and surface commingling of oil and to §3.28, regarding requirements to ascertain and report potential and deliverability of gas wells. The Commission intends to take action with respect to the proposed amendments to §§3.26 and 3.28 at a later date.

The Commission simultaneously readopts §§3.52 and 3.53, with the adopted amendments (in the REVIEW section of this issue of the *Texas Register*), in accordance with Texas Government Code, §2001.039. The agency's reasons for adopting these rules continue to exist. The notice of proposed review was filed with the *Texas Register* concurrently with the proposed amendments and published in the October 22, 1999, issue of the *Texas Register* (24 TexReg 9320).

Texas Oil & Gas Association filed comments supporting the amendments.

Issued in Austin, Texas on December 21, 1999.

The Commission adopts these rules pursuant to Texas Natural Resources Code, §§81.051, 81.052, 85.042, 85.046, 85.053, 85.054, 85.201, 85.202, 86.011, 86.012, 86.041, and 86.042, which authorize the Railroad Commission of Texas to adopt rules for the following purposes: to govern and regulate persons and their operations under the jurisdiction of the Railroad Commission; to distribute, prorate and apportion allowable production; to adjust correlative rights and opportunities; to determine the daily allowable production for each well; to effectuate the provisions and purposes of the Natural Resources Code; and to conserve and prevent waste of oil and gas.

Texas Natural Resources Code, §§81.051, 81.052, 85.042, 85.046, 85.053, 85.054, 85.201, 85.202, 86.011, 86.012, 86.041, and 86.042, are affected by the amendments.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 21, 1999.

TRD-9908942

Mary Ross McDonald

Deputy General Counsel

Railroad Commission of Texas

Effective date: January 10, 2000

Proposal publication date: October 22, 1999

For further information, please call: (512) 475-1295

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Chapter 3. OIL AND GAS DIVISION

The Railroad Commission of Texas adopts the repeal of existing §3.56 and adopts new §3.56 with the same title. New §3.56 is adopted with changes to the proposed text as published in the October 1, 1999, issue of the *Texas Register* (24 TexReg 8402). The repeal and new rule are adopted to remove an unnecessary burden on the operation of gas plants.

In adopting the new rule, the Commission recognizes that it is not necessary to allocate back to individual hydrocarbon producing properties unidentified recovered and retained oil scrubbed at the inlet of a gas plant because that oil has already been accounted for in accordance with §3.27 of this title (relating to gas to be measured and surface commingling of gas).

The Commission has made two changes to the proposed rule based on comments received. The first change adds language to §3.56(b)(1) to specify that an accepted Form R-3 shall be the authority for the movement of accumulated hydrocarbons to beneficial disposition. The second change rearranges the language of §3.56(b)(2)(A)-(E) to distinguish the differences in allocation between single operator and multiple operator systems, and inserts minor clarifying language.

The Texas Oil & Gas Association (TXOGA) filed comments generally supporting the repeal and adoption but also suggested changes. TXOGA suggested adding language to §3.56(b)(1) which would make an accepted Form R-3 the authority for the movement and disposition of accumulated hydrocarbons. The Commission agrees to this change. TXOGA also suggests reordering the paragraphs in §3.56(b)(2)(A)-(E) to clarify the differences in allocation for single operator and multiple operator systems. The Commission generally agrees with TXOGA's suggested re-arrangement, but declines to place the allocation requirements for single operator and multiple operator disposal systems in the same paragraph. In the new arrangement of §3.56(b)(2)(A)-(E), the first sentence of proposed §3.56(b)(2)(A), less the opening phrase "Except as provided in subparagraph (E) of this paragraph," becomes adopted §3.56(b)(2)(A). Proposed §3.56(b)(2)(B) remains unchanged. The second sentence of proposed §3.56(b)(2)(A), less the opening word "Such," becomes adopted §3.56(b)(2)(C). Proposed §3.56(b)(2)(E) is deleted and replaced with the language "Unidentifiable liquid hydrocarbons recovered by a multiple operator produced water disposal system, in excess of a tolerance ratio of one barrel of liquid hydrocarbons for each 2,000 barrels of produced water received, shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period" as the first sentence of adopted §3.56(b)(2)(D). Proposed §3.56(b)(2)(C) becomes the second sentence of adopted §3.56(b)(2)(D). Proposed §3.56(b)(2)(D), less the words "skimmed and" after the word "hydrocarbons," becomes adopted §3.56(b)(2)(E).

Additionally, in the first sentence of §3.56(b)(2)(A), after the word "operator", the Commission has added the words "or multiple operator" to clarify that both single and multiple operator systems must report the volume of unidentifiable hydrocarbons recovered on Form P-18. In the first sentence of §3.56(b)(2)(C), after the word "hydrocarbons," the Commission has added the phrase "recovered by a single operator produced water disposal system" to clarify the type of disposal system to which the paragraph applies. In the first sentence of §3.56(b)(2)(E), after the word "volume," the Commission has added the words "of liquid hydrocarbons" to clarify the nature of the volume that must be reported as production.

The following groups or associations filed comments supporting the repeal and adoption: the General Land Office, Phillips Petroleum Company, GPM Gas Corporation, and the Permian Basin Petroleum Association.

16 TAC §3.56

Issued in Austin, Texas on December 21, 1999.

The Commission adopts the repeal of existing §3.56 pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which provide the Commission with jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and with the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission. Further, §85.202(a)(1) authorizes the Commission to promulgate rules to prevent the waste of oil and gas in its storage, piping and distribution and, under §88.011, to adopt rules to provide for the method of measuring oil and gas produced from any well in this state. The Commission is also authorized under §91.101(4) to promulgate rules relating to the reclamation of oil, condensate and gas.

The Texas Natural Resources Code, §§81.051, 81.052, 85.202(a)(1), 88.011, and 91.101(4) are affected by the repeal.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 21, 1999.

TRD-9908927
Mary Ross McDonald
Deputy General Counsel
Railroad Commission of Texas
Effective date: January 10, 2000
Proposal publication date: October 1, 1999
For further information, please call: (512) 936-7308

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Issued in Austin, Texas on December 21, 1999.

The Commission adopts new §3.56 pursuant to Texas Natural Resources Code, §§81.051 and 81.052, which provide the Commission with jurisdiction over all persons owning or engaged in drilling or operating oil or gas wells in Texas and with the authority to adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the Commission. Further, §85.202(a)(1) authorizes the Commission to promulgate rules to prevent the waste of oil and gas in its storage, piping and distribution and, under §88.011, to adopt rules to provide for the method of measuring oil and gas produced from any well in this state. The Commission is also authorized under §91.101(4) to promulgate rules relating to the reclamation of oil, condensate and gas.

The Texas Natural Resources Code, §§81.051, 81.052, 85.202(a)(1), 88.011, and 91.101(4) are affected by the new section.

§3.56. Scrubber Oil and Skim Hydrocarbons.

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings unless the context clearly indicates otherwise:

(1) Identifiable liquid hydrocarbons–Volume of scrubber oil/skim hydrocarbons that is received at a gas plant/produced water disposal facility where the origin of such liquid hydrocarbons can be clearly identified.

(2) Producing property–A location from which hydrocarbons are being produced that has been assigned a lease identification number by the Commission and which is used in reporting production.

(3) Scrubber oil–Liquid hydrocarbons which accumulate in lines that are transporting casinghead gas and which are captured at the inlet to a gas processing plant.

(4) Skim hydrocarbons–Oil and condensate which accumulate during produced water disposal operations.

(5) Tolerance–The amount of skim hydrocarbons that may be recovered before the produced water disposal system operator must allocate to the producing property.

(6) Unidentifiable liquid hydrocarbons–Scrubber oil/skim hydrocarbons received at a gas plant/produced water disposal facility where the origin of such liquid hydrocarbons cannot be identified.

(b) Disposition of scrubber oil, skim hydrocarbons, and identifiable liquid hydrocarbon volumes.

(1) Scrubber oil. Any scrubber oil that has not been returned to a producing property by the end of a monthly report period shall be reported by the operator of the gas plant on the monthly plant report, Form R-3 (Monthly Report for Gas Processing Plants). The unidentifiable liquid hydrocarbons recovered and reported on Form R-3 may be disposed of at the point of accumulation. The accepted Form R-3 shall be the authority for the movement of the hydrocarbons to beneficial disposition.

(2) Skim hydrocarbons.

(A) All unidentifiable liquid hydrocarbons recovered by a single operator or multiple operator produced water disposal system shall be reported on the Form P-18 (Skim Oil/Condensate Report) for each reporting period.

(B) The unidentifiable liquid hydrocarbons recovered and reported on Form P-18 may be disposed of at the point of accumulation. The accepted Form P-18 shall be the authority for the movement of the hydrocarbons to beneficial disposition.

(C) Unidentifiable liquid hydrocarbons recovered by a single operator produced water disposal system shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period.

(D) Unidentifiable liquid hydrocarbons recovered by a multiple operator produced water disposal system in excess of a tolerance ratio of one barrel of liquid hydrocarbons for each 2,000 barrels of produced water received shall be allocated to each producing property in the proportion that the volume of water received from the producing property bears to the total volume of water received by the system during a reporting period. The produced water disposal system operator shall notify the operator of each producing property of any allocations to that property by furnishing a copy of the allocations as shown on Form P-18 (Skim Oil/Condensate Report).

(E) The operator of each producing property shall report the volume of liquid hydrocarbons allocated to the producing property as production from the property on either Form P-1 (Producer's Monthly Report of Oil Wells) or Form P-2 (Producer's Monthly Report of Gas Wells). The volume allocated back shall be shown as skim oil or skim condensate on the appropriate form.

(3) Identifiable liquid hydrocarbon volumes.

(A) Identifiable liquid hydrocarbon volumes returned to the producing property during the reporting period in which the volume is received at the gas plant/produced water disposal facility shall not be reported to the Commission by the gas plant/facility operator. The gas plant/produced water disposal facility operator shall notify the appropriate Commission district office by telephone prior to the return of such volumes. The movement of these volumes back to the producing property shall comply with §3.72 of this title (relating to manifest to accompany each transport of liquid hydrocarbons by vehicle), commonly referred to as Statewide Rule 85.

(B) Identifiable volumes not returned to the producing property shall be reported to the Commission and to the operator of the producing property on Form R-3 or Form P-18 as prescribed in paragraph (1) or (2) of this subsection. Volumes shall be specifically credited to the appropriate producing property. The operator of the producing property shall report the disposition of such identifiable volumes as either skim hydrocarbons or scrubber oil on the appropriate production report.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 21, 1999.

TRD-9908928
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Deputy General Counsel
Railroad Commission of Texas
Effective date: January 10, 2000
Proposal publication date: October 1, 1999
For further information, please call: (512) 936-7308

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Part 2. PUBLIC UTILITY COMMISSION OF TEXAS

Chapter 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS

Subchapter H. ELECTRICAL PLANNING

Division 1. RENEWABLE ENERGY RESOURCES AND USE OF NATURAL GAS

16 TAC §25.173

The Public Utility Commission of Texas (commission) adopts new §25.173 relating to Goal for Renewable Energy with changes to the proposed text as published in the October 22, 1999 issue of the *Texas Register* (24 TexReg 9142). This section is adopted under Project Number 20944. Section 25.173 will implement the legislative goal for renewable energy development in the state of Texas as set forth in Senate Bill 7 (SB 7), Act of May 21, 1999, 76th Legislature, Regular Session, chapter 405, 1999 Texas Session Law Service 2543, 2561 (Vernon) (to be codified as an amendment to the Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated §39.904).

In adopting this rule, the commission's objective is to establish a renewable energy credits trading program (trading program) and define the renewable energy purchase requirements for competitive retailers in Texas. This rule will (1) implement the statutory mandate in PURA §39.904 to promote the development of renewable energy technologies; (2) encourage the construction and operation of new renewable energy projects at those sites in Texas that have the greatest potential for capture and development of environmentally beneficial renewable resources; (3) reduce air pollution in Texas that is associated with the generation of electricity using fossil fuels; (4) respond to customer preferences that place a high value on environmental quality and reflect a willingness to pay a higher price for "clean" energy acquired from renewable resources; (5) increase the amount of renewable energy available to supply electricity to consumers in Texas; and (6) ensure that all customers have access to energy from renewable energy resources pursuant to PURA §39.101(b)(3).

Texas possesses a vast amount of untapped renewable resources, perhaps more than any other state. The Legislature recognized that economic and environmental benefits would accrue to Texas citizens from the development of those resources by enacting §39.904, which mandates that an additional 2,000 megawatts (MW) of generating capacity from renewable technologies be installed in Texas by January 1, 2009.

The Legislature's commitment to development of the state's abundant renewable resources is derived from the preferences expressed by Texas consumers in favor of renewable power. The integrated resource planning process required that utilities assess customer values and preferences and consider these preferences in their resource plans. In an effort to assess customer values and preferences, utilities across the state polled their customers. Statistically significant samples representing about two-thirds of retail electric customers in Texas indicated a willingness to purchase electricity that was generated by renewable energy resources to improve air quality in their communities and across the state. The customers' preferences, revealed in the polling process, are reflected in PURA §39.904: cleaner sources of energy should be deployed to develop the state's renewable resources and improve the quality of the air in Texas.

Texas has long been a leader in the direct use of energy produced by burning fossil fuels. Although Texas has historically been one of the largest energy consumers in the nation, it has continued to be near the bottom in the production and use of renewable energy. The continued growth of the Texas economy and population will continue to make it one of the leaders in energy consumption. Relying on energy produced by burning fossil fuels has contributed to the degradation of air quality in much of Texas, and reliance on fossil-fueled energy sources in the future will continue this trend. Texas electric customers have placed a high value on environmental quality and have shown a willingness to pay a premium for clean energy sources that benefit their communities and the state of Texas. The renewable energy mandate, coupled with the program for trading renewable energy credits (RECs), will ensure prudent use of clean, abundant, and unused Texas renewable resources in the energy production process in a least-cost manner. Additionally, it allows renewable industry participants from Texas or any other location to compete in a market for renewable energy.

The staff held a public workshop to begin the evaluation of issues related to the renewable energy mandate. During this workshop, a technical taskforce with four working groups was formed to address key issues. Six subsequent task force meetings were held during which stakeholders participated in painstaking negotiations to develop a well-balanced rule to implement the requirements of PURA §39.904. The rule reflects the work products of the task force and working groups, incorporating numerous compromises reached by parties in the technical workshops conducted in this proceeding. Where consensus could not be reached, staff considered all views presented in the workshops and in written comments in drafting the proposed rule, which was approved for publication on October 6, 1999.

On November 5, 8, and 10, the following parties filed comments on the proposal: Automated Power Exchange (APX), Guadalupe Blanco River Authority (GBRA), City Public Service of San Antonio (CPS), Entergy Gulf States (EGS), Public Utilities Board of Brownsville (PUB), Texas Industrial Energy Consumers (TIEC), TXU Electric (TXU), Lower Colorado River Authority (LCRA), Texas Renewable Energy Industries Association (TREIA), Shell Energy Services Company, L.L.C. (Shell), Duke Solar Energy and The Boeing Company (Duke Solar and Boeing), the City of Denton, the City of Garland, and the Greenville Electric Utility System (the Cities), Reliant Energy HL&P (Reliant), Texas-New Mexico Power Company (TNMP), Enron, Sabine River Authority of Texas (SRAT), Southwestern Public Service Company (SPS), South Texas Electric Cooperative (STEC), Central Power and Light Company, Southwestern Electric Power Company, and West Texas Utilities Company, which are the Texas operating companies of Central and Southwest Corporation (collectively, CSW), Environmental Defense Fund (EDF), Austin Energy, East Texas Cooperatives (ETC), Office of Public Utility Counsel and Cities served by CP&L and TXU (OPC and Cities), Texas Electric Cooperatives (TEC), Brazos Electric Power Cooperative and Rayburn Country Electric Cooperative (Brazos and Rayburn), Texas Renewable Power Coalition (Renewable Coalition or The Coalition), Small Hydro of Texas (Small Hydro), and the Texas Public Power Association (TPPA).

On November 22, 1999, commission staff held a public hearing pursuant to §2001.029 of the Administrative Procedure Act. Representatives Leo Berman, Jim McReynolds, Bob Glaze, Tom Ramsay and Senator Bill Ratliff attended the hearing and provided comments regarding the treatment of existing resources in the proposed rule. ETC, SPS, and the Cities also provided oral comments on the proposed section. Any comments provided at the public hearing that were not previously submitted in written comments during this proceeding are summarized herein.

In general, Austin Energy, CSW, Enron, Small Hydro, EGS, Reliant, Duke Solar and Boeing, TREIA, EDF, and the Renewable Coalition complimented the commission and staff for using a consensus-based process involving all interested parties to define the principal elements of the trading program. EDF noted that this proceeding was unlike any other, requiring parties new to this concept to think in new ways about regulatory programs. EDF also commented that the rule as published is exceptional and that Texas is clearly in the position of producing a rule that can serve as a model for other states. Shell Energy commended the commission staff for their work on an extraordinarily difficult rulemaking, stating that the proposed rule undoubtedly will further renewable energy capacity development in Texas. The Renewable Coalition commended the commission and staff for publishing a rule that promises to efficiently achieve the principal goal for renewable energy established by the Legislature. Reliant generally supported the proposed rule as published, while STEC stated that it exceeds the commission's statutory authority, is anti-competitive, discriminatory, and unconstitutional.

Comments on specific questions in the preamble to the proposed rule

In the preamble, the commission sought comment on the penalty provisions set forth in §25.173(n). Parties were asked whether meaningful penalties are necessary to ensure compliance with the trading program requirements and to provide examples of penalty provisions contained in other trading programs such as the Acid Rain Program administered by the Environmental Protection Agency (EPA). Parties were also asked to comment on appropriate monetary fees for penalties assessed to competitive retailers participating in the trading program.

Most of the parties agreed that meaningful penalties were necessary; however, TNMP commented that penalties should not be assessed for competitive retailers who fail to meet their allocation of RECs. TNMP contended that there is no need for a standard dollar per megawatt-hour (MWh) penalty or a penalty based on a percentage of market value. TNMP suggested that a competitive retailer should have until March 31 of each year to make up any deficit of RECs through transactions on the open market.

The Cities commented that the administrative penalty provisions of PURA §15.023 are not applicable to municipally owned utilities or electric cooperatives, because §15.023 is applicable to a "person" regulated under PURA. Municipally owned utilities and electric cooperatives are not within the definition of "person" in PURA §11.003. TXU contended that all trading program participants must be treated equally and should therefore be subject to penalties. TXU proposed adopting a provision stating that an electric cooperative or municipality that opts in to customer choice and participation in the REC trading program thereby voluntarily submits itself to the administrative penalty provisions of PURA §15.023 and the proposed rule with respect to its obligations under PURA §39.904.

Duke Energy, TIEC, TREIA, EDF, CSW, Reliant, TXU, and OPC & Cities generally agreed that the penalty structure proposed in the rule was appropriate. Austin Energy and the Coalition commented that the penalties were not strong enough. Austin Energy recommended that in addition to a monetary penalty, the retail electric provider should also be required to purchase the additional deficit credits. The Coalition likewise commented that the penalty amount should be higher to ensure that the cost of non-compliance is higher than the cost of compliance. Shell, Reliant, TXU, and CSW disagreed with this position.

Shell, TXU, STEC, Entergy, Enron, OPC, and TEC recommended various penalty structure solutions. Shell commented that the proposed fixed penalty scheme violates PURA §15.023(c), which requires the commission to take into account six factors in determining an appropriate penalty amount and that the commission should delete subsection (n)(2) and follow the statutory scheme, using a case-by-case evaluation. If the commission establishes a penalty mechanism, however, Shell suggested that the commission modify the penalty scheme to allow competitive retailers to earn back the penalty through future superior performance, and that the commission preserve the option to assess an appropriate penalty, based on the circumstances. The Coalition disagreed with Shell on this point. Shell also suggested that the commission consider waiving penalties altogether if the year's statewide capacity goal is met. Shell contended that the $50 per MWh penalty exceeds the tolerance margin for non-affiliate retail electric providers (REPs), and that the commission should set penalties only after it knows the prevailing REC market value during the compliance period.

Shell recommended that the commission incorporate a market value, using a two-prong penalty measure. Shell relied on a penalty proposed in an Arizona rulemaking. Shell recommended that the penalty be the lesser of $30 per MWh or the Texas average annual firm peak MWh price during the compliance period. The $30 per MWh penalty would constitute a ceiling, with the penalty otherwise determined according to the prevailing market price. With respect to penalties assessed according to the average market value of credits, Shell contended that the commission can not determine market value unless parties disclose all trade prices to the program administrator. The Renewable Coalition pointed out that the penalty proposed in Arizona is not $30 per MWh, but rather $0.30 per kilowatt-hour (kWh) or $300 per MWh. The Coalition concluded that the Texas penalty is therefore significantly less costly than the Arizona penalty.

TXU commented that $50 per MWh is an inappropriate penalty figure. TXU argued that the monetary penalty should be set not at the total cost of a MWh of renewable energy, but at some multiple of the differential in price between market and renewable energy. TXU further commented that assuming that the market value of credits will reflect the cost differential between renewable power and market power, a reasonable penalty is some multiple of the market value of credits. TXU also suggested graduated penalty provisions. TXU maintained that it is reasonable to base the penalty on the average market value of credits even though price is not required to be reported in connection with the transfer of RECs, because it is anticipated that the necessary pricing information will be readily obtainable. TEC disagreed with TXU's proposal that penalties be assessed on a dollar per MW basis for failure to have sufficient renewable capacity under contract by January 1, 2003. Such penalties would be duplicative of penalties for failure to satisfy the energy-based renewable requirement for 2003. TEC contended such double penalties would be unreasonably punitive. TEC noted that competitive retailers will likely satisfy their renewable obligations through the purchase of RECs instead of contracting for renewable capacity directly, and should not be penalized for failure to contract for the capacity. TEC noted that electric cooperatives that are parties to an all-requirements contract would be precluded from contracting for renewable capacity and that penalties for failure to contract for capacity would discourage such electric cooperatives from offering customer choice until some time after the capacity penalties no longer apply, and capacity penalties would fail to recognize that retail load obligations will change during 2003. TEC observed that this would have the discriminatory effect of subjecting incumbent suppliers to capacity-based penalties, but not new retail suppliers. STEC and Enron agreed that a competitive retailer should not be penalized when it has made a good faith effort to comply with its REC allocation. STEC also urged the commission to modify the penalty provision to incorporate the language suggested by TEC that would expressly exempt competitive retailers from penalties resulting from shortfalls in the renewable energy supplied by the seller of renewables.

Enron and EGS commented that the proposed $50 per MWh penalty is excessive. Both parties stated that the market value of traded renewable energy credits is unknown at this point and contended that penalties that exceed or equal the market value of credits may deter a REP from deciding to enter the market. Enron questioned where the penalties collected will go, and recommended that they be used to offset the program administration costs. Shell agreed with Enron on this point. Enron recommended building upon what other states, such as Massachusetts and New Jersey, have done. Similar to those states, upon the first offense, Enron suggested a public warning be issued and that the commission specify a deadline by which the REP must rectify the deficiency of credits. If the REP does not comply with the commission's order, and depending upon the reason for noncompliance, the commission could suspend the license of the REP or notify the REP's customers of the noncompliance. Enron suggested that the commission may prohibit the REP from accepting or soliciting additional customers if a pattern of noncompliance persists. As a last resort, or in the case of egregious noncompliance, Enron proposed that the commission revoke such REP's license. Shell, Reliant, and CSW agreed in their reply comments with Enron on this type of penalty structure; however, EDF and the Coalition disagreed. Enron further commented that it would be unfavorable to REPs to require them to disclose the average market value of their annual credits in connection with assessing a penalty when the disclosure of the price for credits is not otherwise required.

OPC and Cities commented that if it is significantly more costly to acquire credits on the open market, $50 may not be an appropriate fee because REPs will prefer to pay the fee rather than acquire renewable energy. OPC and Cities further maintained that price disclosure should be required because the assessment of the average market value of credits is likely to be highly inaccurate if price disclosure is not required. OPC and Cities further commented that transaction reports for RECs should include both price and quantity. OPC and Cities contended that the purpose of the REC auction is to balance supply and demand, and to provide a market-based incentive for entry into the renewable resources market. However, if the price of a REC is not disclosed, a potential producer of renewables will have no way of knowing whether a potential for profit exists. OPC and Cities supported the levying of the lesser of two sanctions, such that the $50 per MWh penalty may act as a ceiling thereby preventing the penalty from becoming extremely onerous. TEC submitted that the proposed rule's penalty provisions should recognize the reason for a retail energy seller's failure to meet renewable energy goals and recognize that the retail energy seller can not control the action of the renewable energy supplier. TEC also noted that one element of a competitive market is price disclosure and that prices paid for RECs should be disclosed and made available to market participants on an after-the-fact basis. Several parties referred to penalty provisions contained in the Arizona renewable energy scheme and the Acid Rain program administered by the EPA.

The commission notes that the penalty provisions contained in this section were drafted and discussed in several task-force meetings as one element of a comprehensive program design package. The proposed penalty for non-compliance is the *lesser* of either $50 per MWh or twice the average market value of credits. As many parties agreed, meaningful penalties are a necessary component of a successful trading program; the penalties included in the rule provide a fair and substantial incentive for all competitive retailers to comply with their ongoing REC purchase requirement. Moreover, additional risk-management provisions included in the rule such as six months of early banking, a 5.0% deficit allowance for the program's first two years, and three-year banking allowance for all RECs, provide competitive retailers with the flexibility needed to comply with the requirements set forth in this section. These provisions eliminate the need for any type of graduated penalties suggested by some parties.

The commission disagrees with Shell's suggestion that penalties be completely waived if the state's capacity targets are met in any given year. Shell's proposal would eliminate the incentive for all competitive retailers to comply with the rule and would encourage free ridership and uncertainty in the REC market. The commission also rejects Cities' comment that the penalty provisions in §25.173 do not apply to municipally-owned utilities or distribution cooperatives. PURA §39.002 specifically states that §39.904 applies to municipally-owned utilities or electric cooperatives that offer customer choice. Moreover, §39.002 states that where there is a conflict between the specific provisions of Chapter 39 and other provisions of PURA, the provisions of Chapter 39 control. Section 39.904(c) requires that the commission adopt rules necessary to administer and *enforce* the statute. Under this statutory authority, the commission may enforce the provisions of the proposed rule. Additionally, the commission finds authority to enforce the proposed rule under §39.157(e), which gives the commission jurisdiction to establish a code of conduct that must be observed by municipally-owned utilities or electric cooperatives and their affiliates to protect against anti-competitive practices. Enforcing the provisions of the proposed rule against some competitive retailers and not others would result in competitive advantages for municipally owned utilities or electric cooperatives that offer customer choice. The commission finds that municipally-owned utilities or distribution cooperatives that offer customer choice in the restructured competitive electric power market must be held accountable to the same enforcement standards applied to all other competitive retailers. The commission therefore declines to make any recommended changes to subsection (o) relating to penalties.

Second, the commission asked parties to list the appropriate combination of requirements that would ensure that the electric industry collectively achieves the state's capacity goals in the most economically efficient manner. The commission specifically inquired whether 400 megawatts (MW) of new renewable generating capacity could be installed in Texas by January 1, 2003 if: the credits trading program (1) begins in 2003, (2) allows 5.0% deficit banking for the first two compliance periods, and (3) does not require a new capacity conversion factor to be used until 2006. The commission also sought comment on the appropriate trading program start and end dates.

With respect to an appropriate program start date CSW, Duke Solar and Boeing, EGS, EDF, SRAT, Shell, TIEC, TREIA, and the Coalition stated that the trading program should begin on January 1, 2002. APX, PUB, and OPC stated that the program should begin before January 1, 2003. EDF, Shell, SRAT, and TIEC stated that a January 1, 2002 program start date corresponds with the beginning of competition in Texas. EDF opined that this timeline would ensure that 400 MWs of fully *performing* new renewable resources are in place by January 1, 2003 consistent with §39.904(a) and (c)(2). CSW and TREIA stated that a January 1, 2002 start date would allow renewable generation developers to gradually install renewable facilities during 2002 and could potentially lower the costs to customers if federal legislation extends the renewable energy production tax credit (PTC) through mid-2003.

CSW and the Coalition noted that an extension of the PTC would be limited and require developers to immediately install facilities to insure qualification for the credit. Using a capacity conversion factor of 35%, CSW quantified the potential cost savings to Texans. Assuming that the first 400 MW capacity requirement were installed in time to qualify for the $0.019 tax credit, 1,226,400,000 kWhs could be purchased for $0.019 less than those built without the benefit of the credit, yielding a cost reduction of $23,301,600 in the first year of the program. This annual cost reduction would be reflected in each of the first ten years of service for a project that qualified for the PTC. TXU disputed the savings presented in the CSW example, stating that the start date should not be based on hopes or expectations of congressional action.

Reliant, SPS, TNMP, and TXU stated that the start date for the trading program should be January 1, 2003. Reliant stated that the proposed rule requires contracts representative of new installed renewable capacity to be in place and producing a full year's worth of energy, a requirement not expressed in SB 7. Reliant opined that efforts to enforce penalties against a retail competitor possessing its full allocation of renewable capacity under contract by January 1, 2003 would be legally unsustainable. TXU remained concerned that by using a January 1, 2002 start date, it may not be physically possible to construct the facilities necessary to meet its renewable purchase requirement. TXU submitted a timeline to justify its assertion. Reliant was concerned that transmission constraints in ERCOT might limit the ability of the renewables industry to install 400 MW of capacity in time to meet the target in the draft rule. Reliant stated that a program commencement date of January 1, 2003 would allow transmission providers additional time to upgrade the necessary transmission facilities.

CSW, the Coalition, Shell and TREIA sharply disagreed with TXU's claim that the renewable industry could not install sufficient capacity in time to build 400 MW of new capacity by January 1, 2003. CSW asserted that it is likely that renewable resources will be gradually installed throughout 2002, and the total output supplied by generators will exceed the total energy required for REPs to meet their renewable purchase requirements. CSW also pointed out that TXU's estimated schedule for completion of a renewable project is grossly overstated and maintained that a REP wishing to sign a contract today could receive energy from a 100 MW wind farm within 18 months or less. CSW justified its position based upon its experience adding 75 MW to the Southwest Mesa Wind Energy Project in Upton and Crockett Counties, Texas. This project demonstrated that a substantial wind project could be completed in much less than the 28-42 months suggested by TXU. For example, the turbine order was placed in November 1998 and delivery began in March 1999 at a time that over 800 MW of wind energy was installed in the US. Moreover this 75 MW wind farm was completed and operational within nine months after the commission's approval of the project. CSW also stated that TXU's schedule for completing new renewable facilities ignores the following facts: (1) site identification work is in many cases already done or in process; wind energy sites in Texas have already been leased, optioned or purchased by developers in excess of 400MW, (2) private developers of these wind sites are currently conducting meteorological studies, and (3) environmental studies can be completed in less than three months concurrently with geotechnical and engineering site layout work.

Shell Energy also disagreed with TXU's assertion that the 400 MW target can not be met, mentioning that American National Wind Power (ANWP) is currently developing a 250 MW site in Culberson County. TREIA disputed TXU's assertion, noting that Texas industry is installing more than 145 MW of new renewable resources during 1999 alone. The Coalition stated that TXU's lengthy project schedule may be due to the fact that TXU's Big Spring wind project experienced a series of delays associated with regulatory intervention and litigation, external litigation involving patents associated with the initial technology chosen for the project, and a change in project ownership. The Coalition submitted a project development schedule that it believed was more typical, indicating that the wind power industry, contingent upon REPs appropriately contracting for new renewable energy, could easily achieve the installation of 400 MW of new generating capacity by the beginning of 2002.

Although TXU stated that it would be challenged to meet its projected 160-MW requirement, the Coalition replied that the construction of a 160-MW project is quite feasible. The Coalition illustrated this point with Enron Wind Corporation's two Storm Lake, Iowa projects, built simultaneously, at the same location, and equaling more than 192 MW. The Coalition also pointed out that TXU does not have to obtain all 160 MW of its projected initial REC requirements from one project; it has the option of contracting for output from multiple projects, possibly developed by separate entities. The Coalition justified the industry's ability to build new capacity, stating that during the twelve-month period from July 1998 through June 1999, approximately 1,000 MW of wind power capacity, worth approximately $1 billion, was installed in the United States. TXU also submitted that the time required for wind turbine delivery alone may be closer to 12 months after the manufacturer's receipt of the order. The Coalition was perplexed as to the source of such information and NEG Micon, a member of the Coalition and one of the world's leading turbine suppliers, reported that it can deliver turbines within 14 to 16 weeks after receiving a "Notice to Proceed". Representatives of Vestas, another world leader in turbine manufacturing and Coalition member, stated that deliveries typically occur six to eight months from the date of an order. Enron Wind currently can deliver its domestically manufactured turbines within six months of an order, and internationally manufactured 1.5 MW turbines within two to three months of an order. With respect to the project development schedule, TXU argued that it was aggressively assuming nine months for engineering, procurement, and construction. The Coalition countered TXU's assumption by pointing out that the construction of FPL Energy's 75 MW wind farm was accomplished at a remote and challenging location in only five months.

As an alternative to a January 1, 2003 program start date Reliant, TEC, and TXU proposed using the actual installed faceplate capacity, as verified by the commission or program administrator, to determine compliance with PURA §39.904(a), rather than the energy production required by the proposed rule. The Coalition disagreed, commenting that it is neither appropriate nor necessary to alter a fundamental element of the trading program for the first two compliance periods. Despite the fact that the capacity conversion factor (CCF) is administratively set at 35% for the first two compliance periods, program efficiencies remain an important objective, and it would be disruptive to switch from a capacity-based to an energy-based credits trading program.

With respect to the appropriate trading program end date, CSW, the Cities, EGS, Reliant, SPS, TIEC, and TNMP stated that the end date for the trading program should be in 2009 because there is no legislative requirement that the trading program extend beyond that date. The Coalition disagreed with this assertion, stating that the directive of PURA §39.904(c) requires the commission to adopt rules necessary to administer and enforce the renewable energy mandate; this language sufficiently supports the commission's initiation of program requirements prior to 2003, any early banking provisions, and continuation of program requirements beyond 2009. The Cities and SPS stated that §39.904 milestones are evaluated on the basis of whether renewable capacity has been installed. The Cities also stated that extending the end date beyond 2009 is inconsistent with preamble language that there will be no economic costs incurred by persons who are required to comply with the new rule beyond those costs caused by the underlying statute that it implements. Extending the compliance period an additional ten years, Cities continued, will significantly increase costs for parties that must purchase renewable energy credits.

EGS and TXU acknowledged the concern that some stakeholders have expressed that in order for RECs to be available for trading through 2008, renewable energy generators must have certainty that a market will exist for their renewable capacity after January 1, 2009. This concern is that investors will be unwilling to fund a renewable project in years 2007 and 2008, and perhaps earlier, unless they can be sure that there will be buyers for this capacity after January 1, 2009. Both EGS and Reliant argued that the commission may not unilaterally decide to continue the program beyond 2009 without a specific mandate in SB 7. CSW, the Cities, EGS and Reliant opined that conformance with the end date of the statutory goals need not hinder the credits trading program if it needs to operate beyond 2009. CSW stated that the Legislature would be in a position to extend the program if necessary.

Austin Energy, Duke Solar and Boeing, EDF, OPC and the Cities, TREIA, and the Renewable Coalition stated that the end date for the trading program should be December 31, 2019. Austin Energy, OPC and the Cities, and TREIA, and the Coalition maintained that the program must have an extended end date to provide a sufficient level of certainty for financing renewable investments. EDF stated that ending the program in 2019 should provide enough time for suppliers to recover the costs of previous investment in renewables as well as those costs associated with the last 600 MW capacity installment required in 2008. If the program is not extended, continued EDF, renewable energy providers may be forced to try and recover these capital costs in only a year or two of sales with extremely high prices containing an additional risk premium.

CSW, Enron, EDF, OPC and Cities, and Shell suggested that under appropriate circumstances, the program could be ended earlier than 2019 using a market-based approach. These parties concurred that the program could essentially end automatically as the cost of renewable energy decreases over time and the price of a renewable energy credit becomes zero dollars. These parties proposed that the commission should determine the program's termination date at a later time based on empirical evidence justifying that a trading program would no longer be necessary to sustain the mandate. Shell added that an uncertain end date might accelerate the installation of new renewable capacity. TREIA countered that an end date of 2019 was better than a market-based approach. TREIA asserted that self-sunsetting actually would increase compliance costs by introducing risk for projects built prior to 2009. If the value of RECs go to zero, TREIA continued, the only advantage that REPs would gain from "self-sunsetting" would be the elimination of administration costs, which are expected to be low.

In response to questions regarding deficit banking, PUB, OPC and Cities, Reliant, TIEC, and TXU, supported the flexibility offered by the prospect of 5.0% deficit banking. OPC and Cities noted that the concept of deficit banking is one part of the compromise created by the task force members to garner support for the strong penalty provisions of this section. Reliant presented a numerical example of deficit banking that showed it could work as a risk management tool while still allowing compliance with the 2003 mandate.

EDF, OPUC and Cities, SPS, TREIA and TIEC were concerned that the 5.0% deficit banking allowance could reduce the commission's ability to ensure that capacity goals are met. SPS supported the position that any shortage banked under the deficit banking provision should be made up in the following year. EDF further stated that deficit banking is not needed as a risk management tool.

With respect to an appropriate CCF, PUB agreed that the commission should use actual capacity factors to calculate the CCF in the future as actual performance of technologies becomes known. Reliant suggested that the CCF be adjusted biannually. TIEC stated that the CCF should be adjusted in 2004, not 2006. TREIA argued that the 35% fixed CCF reduces the commission's ability to ensure capacity goals are met. The Coalition stated that achieving the initial capacity target set by the Legislature depends in large part on whether the initial 35% CCF is accurate and that the end of the program's first year will illustrate whether or not that is the case. The commission should therefore reevaluate the CCF and assess the success of the program during the program's first settlement period in the first quarter of 2003.

SPS stated that wind turbines likely will perform below the proposed 35% capacity factor in its service territory. SPS's most recent project is anticipated to have a 32% capacity factor. SPS argued that it will have to add 10% more turbines to achieve its energy purchase requirements set forth in the proposed rule.

The commission agrees with TIEC, CSW, Duke Solar and Boeing, the Renewable Coalition, Shell, EDF, TREIA, and SRAT, that the REC trading program should begin on January 1, 2002, for several reasons. First, Congress has extended the 1.9 cents per kWh PTC for wind energy. To qualify for this credit, facilities must be producing energy *no later* than December 31, 2001. This credit will significantly reduce the cost of wind energy and will lower program compliance costs for competitive retailers and their customers. A January 1, 2002, program start date should provide an incentive to complete projects before 2002, so as to qualify for the PTC. Second, the commission is not persuaded by TXU's position claiming that developers can not build sufficient resources before January 1, 2002. As CSW, the Coalition, and Shell Energy discussed, prudent buyers and sellers of renewable energy are already making preparations for developing sufficient renewable capacity to meet the first 400 MW target. If wind power is consistently the renewable technology of choice during the next ten years, Reliant's concern about transmission constraints may become a reality. However, this does not appear to be a hindrance to wind energy project development in the immediate future. The commission commits to continue working with the ERCOT ISO and transmission service providers to ensure that transmission constraints are alleviated across the state. This should help mitigate any potential increases in trading program costs associated with transmission congestion. The commission therefore declines to make any of the recommended changes to the program start-date, noting that the provisions as proposed are consistent with PURA §39.904(c), directing the commission to establish a renewable energy credits trading program.

Additionally, the commission declines to amend the program end-date as set forth in subsection (m) of this section and agrees with Austin Energy, EDF, OPC and Cities, Duke Solar and Boeing, TREIA, and the Renewable Coalition that a December 31, 2019, program end date will provide certainty for suppliers financing renewable investments, ensure that all 2,000 MW are installed, and would likely reduce the overall cost of compliance to competitive retailers and their customers. First, the commission notes that the majority of stakeholders were in agreement during the task force meetings that a trading program extending beyond 2009 would decrease compliance costs for competitive retailers and ensure the installation of the final 600 MW of capacity required in PURA §39.904(a). For example, increased certainty for suppliers would likely reduce their financing costs, resulting in reduced overall compliance costs for competitive retailers and their customers. If competitive retailers are not required to hold credits beyond 2009 it is possible that the costs of the last 1,050 MW of required capacity may significantly increase, as suppliers seek to recover the above market costs associated with this capacity over a five or two year period. If the cost of renewable energy or the credits were to increase significantly, competitive retailers might choose to pay the penalty instead of purchasing the energy associated with this high cost capacity, resulting in noncompliance with the statutory requirements set forth in PURA §39.904.

The commission clarifies that a ten-year continuation of the trading program to 2019 does not require competitive retailers to purchase additional capacity beyond the 2,000 MW required in the statute; it merely requires them to hold credits for this period. If the price of credits falls to zero dollars before 2019, the commission, in assessing the program, would end the program if it determines that the trading program is no longer necessary. Second, the commission notes that PURA §39.904(c) requires the commission to adopt rules necessary to administer and enforce the renewable energy mandate. This language gives the commission sufficient latitude for the initiation of program requirements prior to 2003, any early banking provisions, and continuation of program requirements beyond 2009. Moreover, the 5.0% deficit banking provision allowed under subsection (m)(2) will not reduce the commission's ability to ensure that capacity goals are met. All competitive retailers incurring such a deficit must make up the amount of RECs associated with the deficit in the next compliance period. All of these elements of the program set out in the rule contribute to meeting the objective of PURA §39.904, the installation of the specified amounts of renewable resources in a cost-effective manner. The commission therefore determines that the language contained in subsection (m) of this section should not be changed.

Third, the commission sought comment on the metering and verification of renewable energy output as required by this section, asking which parties should be responsible for the metering and verification of renewable energy output data.

Almost all parties agreed that the renewable energy generator should be responsible for metering and verification of energy output data. Only PUB suggested that the program administrator or another independent third party be responsible for metering and verification of energy output data. Reliant, CSW and EDF proposed that renewable energy metering and verification be subject to the same standards as that of any other generator interconnecting to the grid. CSW noted that ERCOT has established generation metering and verification standards in the ERCOT operating guides and suggested that renewable generation should meet and comply with the same standards for interconnection as all other generators in a qualified power region, including metering and verification requirements. TREIA suggested that the program administrator establish such standards.

Boeing and Duke Solar suggested that British thermal unit (BTU) calculations rather than metering could be used to determine the energy saved by generation offset technologies, such as solar water heating. They also suggested allowing the energy produced from renewable sources in hybrid plants to be eligible for credits. OPC and Cities agreed with these changes, TXU objected.

With respect to renewable generators and the reporting of metering and verification data, parties suggested that data be reported to either the ISO or the program administrator. TXU, TNMP, and APX favored reporting directly to the program administrator, while Reliant, TEC, Brazos and Rayburn, and the Renewable Coalition favored reporting to the ISO. OPC and Cities stated that metering and verification information should be shared between the generators, market participants and program administrator.

Many parties proposed that the program administrator would be responsible for the aggregation of the production data and verification of the accuracy of the metered production data. TXU, TREIA, the Coalition, and Shell indicated that this would include making spot checks and audits. Brazos and Rayburn and TEC maintained that the ISO should be responsible for verifying production data as well as generation-offset, off-grid, and on-site distributed renewable resources. According to EDF, the burden of proof remains with the producer, regardless of who does the verification. Enron argued against the existence of a program administrator, proposing that each generator issue its own RECs.

The commission agrees with EDF that the burden of proof remains with the generator. The BTU calculations suggested by Duke Solar and Boeing would be an acceptable method to determine the energy saved by generation offset technologies. However, the commission agrees with other parties that accuracy of metered production data should be verified by the program administrator and amends subsection (g)(9) to reflect this conclusion.

Fourth, the commission sought comment on the banking provisions currently proposed in this section, specifically asking whether the three-year banking provision contained in the proposed section would help ensure that 2,000 MW of new capacity is installed in Texas by 2009. Parties were also asked whether renewable power generators should be allowed to receive credits for energy produced before the first compliance period (early banking) and how the addition of this provision to the proposed section would impact the achievement of the statutory goal.

With respect to a three-year banking limit for RECs, PUB, CSW, Duke Solar and Boeing, Enron, EDF, OPC, SRAT, Shell, SPS, STEC, the Coalition, TIEC, TNMP, and TREIA supported the banking provision. Brazos, Shell, TEC, and TIEC stated that banking will encourage early installation of renewable facilities. EDF stated that the combination of limiting the life of credits to three years and specifying a program end date of 2019 is a good solution and provides operational insurance without jeopardizing the fulfillment of the legislative goal. PUB, the Coalition, Duke Solar, EDF, OPUC, and TREIA stated that the three-year banking limitation will ensure that participants in the credit trading program will build new renewable facilities and not just accumulate credits. These parties argued that unlimited banking might allow competitive retailers to accumulate enough RECs to meet their assigned requirements without having to build the full 2000 MW of capacity by 2009. Brazos Electric, Shell Energy, SPS, TEC, and TNMP noted that the three-year banking provisions will help smooth normal year-to-year variance in output, provide a more stable trading program and facilitate renewable resource planning.

Austin Energy and TXU opposed limits on banking credits. Austin Energy stated that the proposed three-year life of banked RECs arbitrarily restricts banking, a policy that should be encouraged aggressively. TXU commented that a REC represents actual energy production from a renewable resource, and the benefit gained from the production of that energy was actually realized and does not expire; the benefit of renewable energy production is permanent and the REC earned by that energy production should also be permanent.

Duke Solar and Boeing, the Coalition, and TREIA proposed that the commission should articulate the right to alter restrictions on banking at any time in the future it may be deemed necessary to meet the capacity targets. The Coalition recommended that the commission explicitly reserve in the rule the authority to take such action. The Coalition stated that the actions to be taken by the commission in this regard could include limiting the number of credits banked in prior compliance periods that can be used to achieve compliance in the current period, and reducing the effective life of credits to less than three years. CSW, Shell Energy, and TXU disagreed with this position. CSW opined that canceling a banked REC in order to correct a shortfall would in itself lead to shortfalls in renewable resource additions. CSW recommended that the commission adjust the CCF if needed, as recommended in the proposed rule, to reallocate renewable resource purchase requirements to competitive retailers. Shell stated that having the commission retain the discretion to modify banking requirements at any time during the program's existence would introduce significant uncertainty into the trading program.

EDF stated that it would be better to be more conservative in the beginning of the program in determining banking rights and privileges, than to later be in a position requiring the commission to amend those rights if they are found to be harming the legislative goal. SPS stated that too many restrictions imposed on RECs could diminish their value to zero. This limited value greatly reduces the incentive to own excess RECs.

Although early banking is not allowed in the published rule, Austin Energy, CSW, Duke Solar and Boeing, Enron, EGS, the Coalition, SRAT, Shell Energy, STEC, TEC, TREIA, and TXU supported early banking. Duke Solar and Boeing, the Coalition, and TREIA proposed that six months of early banking be allowed for new renewable facilities. The Coalition, STEC, and TXU argued that early banking could provide early liquidity to the REC market. SRAT suggested that early banking should begin as early as 2000 and should be allowed for existing resources. EDF did not oppose early banking *per se,* but found it hard to imagine scenarios that could provide incentives for early construction of new resources and ensure that the interim capacity targets are met. EDF noted that parties favoring unlimited banking, early or otherwise, have failed to provide the mathematical examples the commission requested. Therefore, EDF commented that the three-year limitation on banking should be maintained and no early banking should be allowed. EDF also stated that allowing the banking of credits produced prior to January 1, 2002 could severely affect the goal if qualifying existing post-1995 resources were allowed to be banked. From a policy view, EDF continued, early banking is a tool to encourage early development of resources, and so applying early banking to already existing facilities would be meaningless as an incentive device. EDF noted that a complicating factor associated with early banking is cost recovery. CSW disagreed with EDF and TIEC that early banking would provide some existing eligible resources with an unfair opportunity to double recover their costs, pointing out that the proposed rule clearly excludes any existing renewables from eligibility in the trading program if they are currently receiving cost recovery through base rates or a power cost recovery factor (PCRF).

Austin Energy, CSW, and Shell Energy stated that early banking is an important component of ensuring that the program achieve the initial target of 400 MW of new renewable resources in 2002, creating an incentive to build renewables in advance of the compliance date. Although TREIA stated its concern that early banking serves to lessen the likelihood that capacity targets will be met, it supported the overall package embodied in the proposed rule, and agreed that a modest level of early banking could be tolerated without jeopardizing compliance with capacity goals. Reliant stated that the intent of forward banking is a risk management tool. If the first compliance period is 2003 with a requirement of 400 MW, Reliant continued, early banking should not be necessary.

TIEC opined that early banking does not seem a viable option, because the commission would need to have the registration and certification procedures in place, and the resources would have to meet all eligibility requirements of subsection (e). TIEC also stated that it is likely that the only renewable facilities which could take advantage of early banking would be new resources that would happen to be planned, built, and operated during the short window of September 1, 1999 through December 31, 2001.

The commission notes that the three-year banking provision contained in the proposed section was as part of a comprehensive program design package agreed to by a majority of stakeholders during several of the task force meetings. The majority of parties agreed that this banking provision would provide competitive retailers with additional flexibility in a trading program based on energy produced by intermittent generating capacity. Other parties agreed, that while not ideal, the three-year limitation would help to ensure that competitive retailers contract for new capacity in lieu of holding accumulated credits for the duration of the program. Parties opposed to this provision were afforded the opportunity, both during the workshops and the formal comment period, to raise and provide justification for changes to the three-year banking limitation for credits. The commission finds that parties have not convincingly shown that the three-year banking provision should be either shortened or lengthened in the context of a comprehensive program design package.

With respect to an early banking provision, the commission notes that, during the task force meetings, most parties agreed that an early banking provision would add liquidity to the market by increasing the number of credits that are available at the start of their program. The commission agrees that an early banking provision will enhance the market's liquidity and provide a more functional market at the beginning of the program while maintaining the economic incentives to build new renewable facilities. This will help provide competitive retailers with additional flexibility and important risk management tools needed to comply with the requirements of the trading program, especially in its early stages. The commission clarifies that an early banking provision does not require competitive retailers to buy RECs at an earlier point in time, but rather allows generators to receive RECs for sale in the trading program prior to the program's first compliance period. The commission therefore amends §25.173(m) to reflect this conclusion.

The commission agrees with CSW, EDF, Shell Energy, and TXU that modifying banking requirements at any time during the program's existence would introduce uncertainty and an additional element of risk for competitive retailers forced to comply with the trading program requirements. The commission therefore declines to amend this section to include a provision retaining the right to alter restrictions on banking at any time in the future as it deems necessary to achieve the required capacity targets. The commission points out that adjustments in the capacity conversion factor as set forth in subsection (j) and commission review of the program as set forth in subsection (q), should adequately correct any capacity deficiencies. The commission therefore declines to amend subsection (g)(5) of this section and finds that the language is consistent with PURA §39.904(c) relating to the establishment of a renewable energy credits trading program.

Fifth, the commission inquired whether it would be necessary to build new renewable resources to offset any reduction in capacity resulting from the retirement of any renewable resources in Texas.

Austin Energy, PUB, CSW, EDF, Duke Solar and Boeing, Shell Energy, TEC, TIEC, TNMP, TREIA, Brazos and Rayburn, TXU, and the Renewable Coalition, stated that the goal for new renewable energy in Texas is 2,000 MW by 2009. However, these parties also pointed out that PURA §39.904 also requires a cumulative renewable capacity of 2,880 MW in Texas by 2009. This assumes that 880 MW of renewable capacity currently exists, will continue to operate, and should be replaced by new resources if any are retired. OPC and Cities and Reliant stated that the Legislature intended to have 2,000 MW of new renewables by 2009. The focus should therefore be on installing 2,000 MW of new capacity and not providing a mandate for the maintenance of existing resources. Therefore, the parties concluded, there is no need to build new renewable facilities if any are retired during the life of the program.

PURA §39.904(a) requires an additional 2,000 MW of renewables to be installed in Texas by January 1, 2009. However, this subsection also states cumulative capacity targets for renewables, culminating with 2,880 MW installed in Texas by January 1, 2009. This illustrates the Legislature's assumption that 880 MW of renewables existed in Texas at the time SB 7 was drafted and will continue to be in existence on January 1, 2009. Therefore, if any of the renewable capacity is retired, new renewables to replace that capacity will have to be built. Moreover, if customer demand for renewables exceeds 2,880 MW, market forces could lead competitive retailers to purchase renewable capacity in excess of what is mandated in §39.904(a). Therefore, the commission concludes that the 2,880 MW requirement indicates the minimum amount of renewable capacity that should be installed in Texas by 2009, not the maximum. Changes to the language in subsection (a) are therefore unnecessary. The commission amends subsection (h) of this section to clarify this conclusion.

Sixth, the commission sought comment on the obligation of municipally-owned utilities, distribution cooperatives, and retail electric providers to purchase new renewable resources in the credits trading program if they have existing renewable resources sufficient to cover their renewable energy purchase requirement. Parties were specifically asked whether entities with existing resources should have their obligation to purchase RECs proportionately reduced to reflect the percent of existing renewables they have under contract. The commission also inquired whether it would be necessary to allow existing resources to produce credits for sale in the trading program if those resources are allowed to offset a party's purchase obligation. The commission also asked parties to explain how all of the following conditions could be met: (1) a party's purchase obligation is offset by existing resources, (2) renewable credits associated with those existing resources are excluded from producing credits for sale in the trading program, and (3) the capacity requirements set forth in PURA §39.904 are achieved in a timely, economical, and efficient manner.

Austin Energy, CPS, CSW, EGS, EDF, LCRA, OPC and Cities, Reliant, TEC, TIEC, TPPA, and the Renewable Coalition generally agreed to a compromise approach that would exclude existing renewables from participating in the trading program, but would allow entities participating in retail competition to use existing resources which they own or purchase to satisfy all or part of their renewable obligation. The principles of this compromise are as follows: (1) existing renewable resources as defined in §25.173(c)(5), other than qualifying existing resources as defined in proposed §25.173(c)(10), that are currently owned by or under contract to an entity would count toward its allocated requirement for as long as they remain under contract (including renewal) or are owned by the entity, (2) existing renewables, other than qualifying existing resources as defined in proposed §25.173(c)(10), may not participate in the REC trading program, and (3) regardless of when an entity chooses to opt into competition, there should be a one-time, up front nomination of the existing renewable resources (based on a ten-year average MWh output) that will be used to offset its allocated requirement. LCRA stated that its proposal would allow those who already own or purchase renewable capacity to count such capacity or purchases toward the allocated renewable requirement. Such a proposal can not produce windfalls, precisely because the contracts for such renewables are already in place and can not arbitrarily be broken. Such resources can not flood the market because they are already dedicated to existing customers. The price of credits will not affect the price of energy already under contract, nor produce benefits to the owners of existing resources, windfall or otherwise.

CPS, OPC, Brazos and Rayburn proposed methodologies that could be used to offset renewable purchase obligations for entities with existing resources. The Coalition recommended that the commission take great care in implementing the offset for existing resources, as different approaches could have dramatically different implications for the achievement of the program's objectives. For example, OPC's proposal would actually result in less than 2000 MW of new renewables being built, as requirements to buy new renewable RECs are reduced for the owners of existing resources, but are not reallocated to other competitive retailers. Additionally, Brazos Electric's proposed approach would give disproportionate value to existing renewables. The initial allocation of REC requirements would be based on the market shares of all participating retailers. Existing renewables would offset REC requirements, for those that own existing renewables. The total REC requirement would then be allocated across the smaller, remaining base of REPs. The ratio of RECs required to total sales on a per-REP basis would be higher in this allocation than in the initial allocation. With no readjustment of the allocation for the exempted owners of existing resources proposed, the result is that existing resources would have a disproportionate value, relative to new resources, in achieving compliance with program requirements. The Coalition agreed with CPS's proposal, stating that it includes two allocation stages, correctly providing that REC responsibilities are relieved for owners of existing resources on the same basis as they are assigned for REPs which own no existing resources. The Coalition stated that the commission must limit this benefit to output that is under contract exclusively for resale to retail customers. Without such a limitation, this output could be sold and resold on a wholesale basis. TXU objected to an "offset" concept that would use a historical average of energy output from the existing resources in determining the amount of "offset", maintaining that actual energy production each year should be used. TXU and CSW also suggested that, to the extent that trading program compliance is based upon energy, the "offset" provided by existing resources be based upon actual energy produced, and not capacity.

TXU opposed any offset provision. CSW agreed, but stated it was willing to accept a compromise comparable to CPS's proposal. TXU stated that it is unfair and discriminatory to allow those entities to offset their obligation using old, low-cost, low-capacity factor facilities, the capital cost of which may have already been recovered through rates, and will also increase the costs that all REPs, including new REPs, will bear as they enter the competitive market in 2002. TXU further stated that such an exemption would allow municipally owned utilities (MOUs) and electric cooperatives to avoid their responsibility to support the legislative goal at the expense of all other retail competitors. Only MOUs and cooperatives with existing resources would be able to take advantage of this exemption because REPs will not be allowed to continue ownership of generation facilities, renewable or otherwise, following the advent of retail competition. Brazos and Rayburn and the Cities preferred that existing resources be included in the trading program, but that a reasonable compromise would be for municipally owned utilities and distribution cooperatives to offset part or all of their REC requirements with existing renewable resources currently under contract. PUB and State Representatives Merritt and Zbranek supported some form of offset of REC requirements for municipally owned utilities and distribution cooperatives purchasing power from existing renewable resources. CSW alternatively suggested using a "cost test" to qualify existing renewable resources for participation in the trading program. The "cost test" would allow existing renewable resources to prove that their costs were above those of other resources for sale in the wholesale market. Any existing renewables meeting these cost criteria would be allowed to participate in the trading program.

STEC commented that the offset, in principle, was a good basis for a negotiated compromise. EDF strongly preferred this type of solution because it maintains the trading program solely for new resources, allowing that market to operate correctly by setting prices that minimize the ultimate cost to Texas citizens. Brazos and Rayburn and ETC stated that for those cooperatives that do offer customer choice, their load ratio share of their generation and transmission (G&T) cooperative's existing renewables should count toward such opt-in cooperative's REC allocation.

Many parties with existing renewable resources explained why these resources should be allowed to participate in the trading program. APX, Brazos and Rayburn, PUB, ETC, GBRA, SRAT, TEC, TNMP, and State Representatives Wohlgemuth and

Zbranek commented that the commission should incorporate existing renewables into the credits trading program, as the continued operation of existing renewables is important in increasing the total MW of renewables operating in Texas. APX, Brazos and Rayburn, and TEC stated that the cost of trading RECs from existing resources would be no higher, and perhaps lower, than the cost of the trading program in which only new resources earned trading credits. APX opined that the commission can define the percentage of new RECs and existing RECs each competitive retailer must purchase to comply with the rule and provide the regulatory push desired to encourage the development of new renewable resources.

GBRA explained that many of the large incumbent providers oppose the inclusion of existing resources in the rule because they have a minimum amount of renewable capacity in their existing mix. By increasing the number of potential suppliers in the market to include existing resources along with entities that construct new projects, the market price for credits should in fact decrease, resulting in an overall benefit to the market. ETC and State Representatives Telford and Wohlgemuth also stated that out-of-state renewables should be included in the trading program in order to be fair to the rural ratepayers and constituents in East Texas. EDF responded by stating that the list of the 880 MW of renewables used by the Senate Interim Committee on Electric Utility Restructuring did not include the 128 MW of out-of-state Southwest Power Administration (SWPA) hydropower allocated to cooperatives in East Texas.

CPS, Coalition, Duke Solar, EDF, OPUC, Shell Energy, and TXU stated their opposition to including existing renewables in the credits trading program. They maintained that awarding RECs to existing renewable resources would seriously undermine the market for new renewable-resource credits and would jeopardize the state's ability to achieve the required amounts of new renewable-resource generating capacity in a cost-effective manner. OPC and the Coalition commented that the inclusion of existing renewables in the program will be more costly in the short-run and decrease the margin for competition in the early, formative stages of the market for electricity. Additionally, the Coalition, Reliant, Shell Energy, and TXU stated that if existing renewables received RECs that their owners would receive an undeserved windfall. TXU provided a mathematical example of such a windfall, concluding that the windfall would be substantial. For example, assuming that the cost of credits averages $10 per MWh over the first ten years of the program, and assuming a 20% capacity factor for existing renewable resources, the value of the credits provided to existing facilities would be over $153 million. TXU stated that owners of existing renewable facilities should not receive a windfall of this magnitude.

The Coalition stated that if owners of existing renewable-generation were awarded only one-half the amount of credits awarded to owners of new facilities, this windfall would be merely reduced, not eliminated, again without producing any additional renewable-resource capacity. Likewise, awarding new renewable resources two credits per megawatt-hour would reduce, but not eliminate, the number of existing resources wielding a competitive advantage over new renewables. Shell Energy stated that it has not seen any data or studies to show that an additional credit per MWh constitutes a sufficient investment incentive to overcome the deterrent effect that existing resources' incumbency advantage would create, or that competitive retailers would purchase energy from these new projects, at a higher cost, simply because they would receive more RECs.

TXU stated that requiring new projects to compete with existing resources in the market for renewable energy credits would create a serious market power issue, particularly during the early years of the program, when the amount of existing renewable capacity will significantly exceed that of new capacity. Even by 2005 and 2006, the existing amount of renewable energy capacity (880 MW) will exceed the goal for new capacity (850 MW). By restricting the credit-trading program to new resources, market power concerns will be greatly minimized. Third, the presence in the credits market of significant amounts of lower-cost, existing renewable sources could inhibit the timely contracting for credits from new sources that will be necessary to support the development of those sources. This could occur if the owners of those lower-cost, existing sources withhold their credits from the market, in anticipation of higher credit prices to be set by new renewable generation, and buyers of credits delay their purchases in hopes of securing lower-cost credits from existing sources. TXU stated that this would stifle the goal of having new generation in place according to SB 7.

CPS stated that simple economics dictate that, in a competitive generation market, the sustainability of an existing renewable resource is jeopardized only to the extent that the incremental production costs of the resource are in excess of the market price of electricity. While some parties have presented data indicating that the *total cost* (i.e., embedded and incremental costs) *may* be greater than the market price for some renewable resources, no data has been presented that would indicate that any of the existing base of renewable resources has incremental production costs that exceed the expected market price of electricity. Given these circumstances, the inclusion of existing renewable resources in the REC trading program serves only to: (1) provide a market-based subsidy toward the recovery of embedded costs that are rightfully addressed in the context of stranded costs (i.e., in the case where the total cost of the renewable resource is greater than the market price); or (2) provide windfall profits to the owners of existing renewable resources (i.e., in the case where the total cost of the renewable resource is less than the market price). CPS does not believe that the REC trading program was created to provide stranded cost subsidies or windfall profits; rather, it was created with a sole purpose in mind-to achieve an *additional* 2,000 MW of renewable resources in the State by 2009.

With respect to the competitiveness of existing hydroelectric facilities, Brazos and Rayburn, GBRA, LCRA, and SRAT noted that the cost of production from their existing hydroelectric resources exceeds projected market values. LCRA stated that the resources are expensive to maintain and the ability to release water to generate electricity is limited by water rights. The resultant output, according to LCRA, GBRA, and SRAT, when apportioned over the cost to operate and maintain the facilities, produces a cost of $36-$38 MWh for LCRA to over $70 per MWH for GBRA and SRAT. LCRA stated that these costs make the hydroelectric resources unable to compete against new combined cycle costs or existing generation for which stranded costs have been recovered. EGS and LCRA argued it would have little incentive to maintain their hydro resources under those circumstances. Brazos Electric provided information on several of its existing hydro contracts, stating that low annual capacity factors and age of these facilities result in average costs that are above market. Therefore, the energy associated with these facilities should be used to generate RECs.

Reliant and TXU expressed skepticism about the claims of the river authorities and stated that more detailed information would be needed to persuade them that hydroelectric resources are in need of assistance. In any event, Reliant and TXU stated that municipal and cooperative electric utilities that opt in to customer choice could recover their stranded costs pursuant to the relevant provisions of PURA Chapters 40 and 41, respectively. Shell Energy stated that the commission should ignore threats that some parties will close their facilities if it does not extend further preferences and subsidies to these already subsidized facilities. Most existing resource owners can sell this energy through existing long-term contracts. Shell questioned the notion that LCRA, whose main purpose is to build and maintain dams and which is adding even more generation capacity to meet all its long-term requirements contracts, will shut down its lucrative generating facilities.

Austin Energy, Brazos and Rayburn, CPS, DGG, Entergy, LCRA, TEC, TIEC, and TPPA took the position that the Legislative mandate in PURA §39.904 includes existing resources. As such, the rule must provide a mechanism that allows for the continued operation of these resources because the 880 MW of renewable resources in existence when the Legislature enacted SB 7 is included in the mandates for 2003, 2005, and 2007. The proposed rule acknowledges this mandate by stating that one of its purposes is "to ensure that the cumulative installed renewable capacity in Texas will be at least 2,880 MW by January 1, 2009."

ETC stated that under the proposed rule none of the hydro power currently under long term contract to Tex-La, NTEC, or SRG&T would count in the renewable energy program, and any member distribution cooperative opting in to retail competition would have to purchase additional renewable energy credits ("RECs") to satisfy the renewable allocation assigned by the program administrator. Not only is this result inequitable, it could run afoul of the provisions of the all-requirements contract between each G&T and its member distribution cooperatives, which already provide for the distribution cooperative's full requirements. ETC continued by stating that in practical terms, the cost of having to acquire a completely new renewable energy allocation is estimated to be, over the 11 year period beginning in 2002 and ending in 2012, on average more than $1.5 million per year for the East Texas Cooperatives' distribution cooperatives if they opt in to retail competition.

The Cities stated that the proposed rule does not acknowledge that municipally-owned utilities were making investments in hydroelectric facilities without having to be pushed into doing it by the commission or the Legislature. Therefore, it is only fair that these units, and others like them, be included in the credits trading program.

TXU stressed that existing renewable resource facilities were built for purposes other than to meet the requirements of PURA §39.904. Dams were built mainly for flood control, water storage, or recreation, with low-cost electricity being a side benefit. TXU emphasized that the ability to obtain power from hydroelectric projects was generally limited to only certain types of entities due to federal preference provisions. Thus, ownership of existing renewable resource facilities constitutes roughly three-fourths of the 880 MW of existing renewable capacity and is skewed towards certain types of entities (mainly river authorities, cooperatives, and municipalities). It would therefore be unfair to provide a monetary benefit to these entities when other utilities in the past simply did not have the opportunity to avail themselves of such renewable resource facilities. Shell Energy rejected the fairness argument submitted by entities with existing renewables, questioning whether it is fair that cooperatives and municipal utilities obtained subsidies and preferences for their renewable resources, while IOUs could not. Shell opined that the cooperatives and municipal utilities built these facilities for reasons of their own choosing to suit their own needs. Shell suggested that the commission should only care whether its rule complies with the legislation.

The commission concludes that existing resources should not be allowed to participate in the credits trading program. The purpose of the trading program is to ensure that 2,000 MW of new renewables are installed in Texas in an economically efficient and least cost manner. This purpose is consistent with PURA §39.904(a), which requires 2,000 MW of new renewables to be installed in Texas by 2009 and §39.904(b), which requires the commission to establish a renewable energy credits trading program. Allowing existing resources to participate in the trading program would either increase costs to all competitive retailers required to comply with the requirements of this rule or reduce the value of RECs so that they do not provide adequate incentive for new producers to add new renewables. For example, a trading program that allowed both new and existing resources to participate would require that each competitive retailer buy a proportionate amount of energy from its "share" of a 1,280 MW obligation for the 2003 compliance milestone. Alternatively, a trading program that allowed only new competitive resources to participate would require each competitive retailer to buy a proportionate amount of energy from its "share" of a 400 MW obligation. During the program's first compliance period, including existing renewables in the trading program would increase a competitive retailer's REC allocation by approximately 300%. If the market value of the RECs is based on the cost differential between new renewables and other new resources, a competitive retailer's costs would increase by 300%. This could serve as a barrier to entry for many REPs attempting to do business in a newly restructured electric power market. Alternatively, the availability of RECs from existing resources might create an oversupply of RECs and depress their value. In this case, the value of the RECs would be inadequate to provide producers sufficient incentive to build new renewable capacity.

Additionally, the commission agrees with the statements of some parties questioning the arbitrary nature of the term "qualifying existing resources" defined in the proposed rule and concludes that it would be more equitable not to allow these resources to participate in the trading program.

However, the commission recognizes that cumulative capacity targets also are stated in PURA §39.904(a). The commission applauds all entities in Texas that have realized the benefits of renewables and have taken the initiative to invest in renewables without the requirement of a mandate such as that contained in SB 7. The commission concludes that an "REC offset allowance" would realize the benefits of existing renewables and ensure that the 880 MW of these resources envisioned in §39.904(a) continue to be utilized until January 1, 2009. This offset allowance would allow all entities with existing renewables to use these resources to proportionately offset their renewable energy purchase requirement for new renewables. This offset allowance shall ensure that the cumulative capacity targets required in §39.904(a) are achieved in a manner that does not unnecessarily raise costs of the overall program to Texas customers.

The commission reflects these conclusions by (1) allowing only facilities installed and placed in service on or after September 1, 1999, the effective date of §39.904, to be considered new and eligible to participate in the credits trading program, with the exception of small producers as defined in subsection (c) of this section, and (2) allowing all competitive retailers to receive an offset for existing facilities owned or under contract by the competitive retailer, its affiliates, or its predecessor nominating the resource since September 1, 1999. Allowing an entity that owns existing facilities or takes power under contract from existing facilities to share the related renewable offsets with its affiliates will assure an equitable allocation of the benefits of having obtained those existing resources. For the purposes of this rule only, the commission determines that all of the individual G&T members of ETEC and STEC and the distribution cooperative members of the individual G&Ts, for example, are affiliates of each other. As a consequence of this determination, these members could use their collective existing facilities or renewable power contracts–whether individually or collectively owned–to ratably share the offset created by those resources. The offset approach has broad support among the parties, will ensure that all entities with existing resources receive the same benefit for those investments, and supports the goal of installing 2,000 MW of new capacity in a cost-effective manner. Providing offsets will also make it easier for cooperatives and municipal utilities that have rights to such existing resources to opt in to competition. The commission agrees with the offset methodology proposed by CPS during the formal comment period. This methodology includes two allocation stages, correctly providing that REC allocations are reduced for owners of existing facilities on the same basis as allocations are made for competitive retailers owning no existing renewable resources. The commission therefore amends subsections (c), (h), and (i) to reflect these changes.

Seventh, the commission sought comment on alternative ways to restructure the credits trading program and specifically requested comments on the proposal outlined in Chairman Wood's October 8, 1999 memo filed under this project number. Parties were specifically asked whether existing renewables should be incorporated into the credits trading program and, if so, what impact this would have on (1) the cost or value of RECs over time, (2) the level of financial incentive offered to new renewable resources, and (3) the overall cost of the trading program. Additionally, parties were asked to explain any necessary changes in the REC allocation methodology set forth in subsection (h) of this section and the capacity factor calculation methodology set forth in subsection (i) of this section to accommodate existing and new renewables.

Entergy, GBRA, and TNMP were supportive of Chairman Wood's proposal. Entergy stated that the distinction between existing and new renewable capacity for the purposes of awarding credits should not unreasonably complicate the credits trading program or affect its costs. GBRA stated that the inclusion of all existing renewable resources in the renewable energy credit (REC) trading program, except those for which the costs are (1) recovered from retail customers who do not have customer choice or (2) recovered as eligible stranded costs, is essential to further the legislative goal of 2,880 MW of cumulative renewable capacity by January 1, 2009. In addition, GBRA opined that Chairman Wood's proposed additional one credit/MWH for projects less than ten years old will create incentives for new projects in the market. ETC viewed the Chairman's proposal as a good faith, positive effort to resolve the pending disputes but proposed that it be amended to provide that a distribution cooperative can opt in whenever it chooses to.

Senator Ratliff, State Representative Telford, Austin Energy, PUB, CPS, CSW, LCRA, Shell Energy, SPS, TPPA, TREIA, the Texas Renewable Power Coalition, and TXU disagreed with Commissioner Wood's proposal. Shell Energy stated that the proposal fails to address the potential renewables market power advantage that those possessing existing resources would obtain if they participated in the program. Awarding an additional credit per MWh for the first ten calendar years, Shell opined, only partially mitigates this concern. Shell Energy questioned the statement in Chairman Wood's memo that the commission should ensure stability in pricing for the REC program, commenting that enforced stable REC pricing could actually prevent reaching the program's goals. SPS stated that preferential treatment in the issuance of more than one credit for each MWH of production also adds to the allocation problem. For example, if more than one credit is issued for some MWHs of generation, then the allocation must be increased so that these additional credits are absorbed and needed by the REPs, or there would be no need to build generation because the excess credits can satisfy the regulatory requirement in energy but not the legislative capacity requirement.

The Coalition argued that awarding new renewables the additional credit for only the first ten years would effectively require them to compete directly with lower-cost existing renewables beginning in their eleventh years and for the remainder of their service lives. As a result, developers of new renewable projects would seek to recover more of their costs during the initial ten-year period, resulting in higher costs to consumers during the first ten years of operation. The Coalition also averred that awarding post-1995 renewable-resource facilities two credits for each unit of output during the first ten years of their operation would create two classes of new renewables for the years after 2005, those ten or fewer years old which receive two credits per megawatt-hour, and those more than ten years old which receive only one. Over time, the relative proportions of these two classes would change; adding complexity to the calculation of the energy production goals needed to achieve the statutory capacity goals. TXU stated that is was unclear how providing a differential number of credits to certain resources will result in the levels of capacity set out in PURA §39.904(a) actually being installed in this state. To the extent double credits are provided, those double credits simply halve the amount of energy production that must be achieved by new facilities.

Austin Energy stated that although the collaborative process did not lead to resolution of every outstanding issue, it is inappropriate to look for an entirely new approach as a substitute at this time. Instead, Austin Energy asserted that the commission should act decisively to resolve the few remaining issues in the renewables rule. Such action will strengthen the collaborative process that has been used extensively and quite successfully to date during the remainder of SB 7 implementation rulemakings. Without explicitly opposing the Chairman's proposal, Reliant and STEC thought the proposal had problems that could cause complications for enacting the renewables mandate. In considering alternative ways to restructure the credits trading program, Reliant Energy urged caution, stating that it is often difficult to predict how changes to one aspect of the program might affect overall results and could have the unintended effect of compromising achievement of overarching program goals. Austin Energy concurred with this opinion, stating that the Chairman's alternative proposal has simply not undergone the rigors of the collaborative process. Austin Energy stated that if the details required for his suggested implementation were fully developed, it would become clear that the alternative is significantly more difficult to implement and operate than is staff's proposal.

Austin Energy, PUB, CPS, DGG, ETC, LCRA, STEC, State Representative Telford, TEC, TPPA, and State Representative Wohlgemuth stated that the commission should not or can not make opting for customer choice by January 1, 2002, a prerequisite for participating in the credit trading program. PUB, the Cities, and STEC stated that such an incentive is discriminatory because it creates a cut off date to participate in the credit-trading program. Austin Energy, TEC, and TPPA stated that the Chairman's apparent attempt to entice cooperatives to opt-in sooner rather than later conflicts with the position taken by the legislature in SB 7. There, the legislature expressly provided individual cooperatives the ability to determine whether and when they will offer customer choice. Rather than legislate provisions penalizing cooperatives for not offering customer choice by a certain date, SB 7 establishes a policy of maximum flexibility for cooperatives. TPPA also explained that its members' systems are actively making preparations for industry restructuring, and will consider participating in new retail markets authorized by SB 7. However, most are taking a cautious approach, and the local decision to "opt-in" will not be made until local authorities judge that new markets offer clear benefits to their consumers and communities. Brazos and Rayburn, ETC, STEC, and TEC stated that not all, and perhaps few, municipal utilities and G&T cooperatives will opt-in by the first day of retail competition (January 1, 2002). LCRA presumed that it would be subject to the same standard as the G&T cooperatives, and, as a result, none of its 44 wholesale customers could count LCRA's existing renewables if but one of the 44 declines to opt in. CPS opined that the renewable energy goal and the REC trading program have nothing to do with retail competition, as the same type of program could have been implemented in the context of a mandatory purchase requirement on integrated, regulated utilities. Rather, the goal and the program are about creating a public good through a market-based program in an effort to promote least-cost solutions. CPS and TPPA stated that the rationale for the proposed linkage to retail competition is unclear and unwarranted, especially as applied to new resources.

If existing resources were somehow included in the REC trading program, TXU Electric would support the concept that before any of a G&T cooperative's renewable resources could participate, all of that G&T cooperative's distribution cooperatives would have to opt in to retail choice. The decision on whether to opt in to retail choice and participate in the REC trading program would have to be known some time well in advance of the REC program start date, so that all of the other REPs would know the overall impact of the inclusion of existing resources in the REC trading program. Otherwise, REPs will not have sufficient time in which to know what their likely REC requirement would be, and to make plans to meet that requirement.

Austin Energy, CPS, STEC, and TPPA were concerned that the proposal is intended to indefinitely exclude any new renewable resource from the REC trading program for entities that have not opted-in to retail competition by January 1, 2002. As a general matter, CPS submitted that any new renewable resource located in the State of Texas will certainly contribute toward the 2,000 MW goal of PURA §39.904(a), regardless of the opt-in or out status of a particular entity. Therefore, all new resources should be included in the wholesale REC trading program that was created by the Legislature to achieve that goal.

Shell Energy did not support Chairman Wood's proposal, but expressed the view that if the commission decides to move in that direction, it should not accept the cooperatives' and municipal utilities' complaints about tying this provision to their entering competition on January 1, 2002. These entities never cite any statutory provision that would preclude the commission from doing so. At best, some of those parties simply cite a supposed legislative intent they derive from the Act's overall framework. None, however, cite any provision prohibiting the commission from confining the program to those parties that enter competition by a certain date. Requiring those entities to enter competition at the outset to utilize their existing resources does not constitute any manipulation or usurpation of their statutory rights.

As noted in response to comments received on preamble question six, the commission concludes that existing resources will not be allowed to produce RECs for sale in the trading program and that the offset methodology suggested by CPS is a more cost-effective approach to equitably implement PURA §39.904. The applicability of this offset provision for distribution cooperatives and municipally-owned utilities *does not* require all of a G&T's distribution cooperatives to offer retail choice by 2002, a concept proposed by Chairman Wood and opposed by many parties.

Comments on proposed subsections

Several parties provided additional comments on various subsections of the proposed rule. Comments not previously summarized and addressed as part of responses to questions posed in the preamble are discussed below.

Comments on §25.173(a)

OPC and Cities opposed the language in this subsection ensuring that the cumulative installed capacity in Texas will be at least 2,880 MW by January 1, 2009. OPC and Cities argued that the legislative goal is met when 2,000 MW of new renewable energy is installed in Texas. These parties proposed that this language either be deleted, or at a minimum, the words "at least" be removed.

As noted in response to preamble question number five, the commission does not find it reasonable to change this language. Subsection (a) expresses the statutory goal that a cumulative renewable capacity of at least 2,880 MW be installed in Texas by January 1, 2009.

Comments on §25.173(b)

EPE suggested that an additional sentence should be added to the applicability subsection of the rule, which states that this section shall not apply to an electric utility not subject to PURA §39.102(c).

The commission concludes that EPE is not subject to the provisions set forth in these sections until the expiration of the utility's rate freeze period and amends subsection (b) to reflect this conclusion.

Comments on§25.173(c)

GBRA and Cities commented that the definition of "small producer" under subsection (c)(18) of the proposed rule should be increased from two megawatts to five megawatts to ensure the viability of small hydroelectric units and to be consistent with the federal law definition. The Coalition opposed GBRA's proposal, stating that the two MW threshold resulted from a unique situation, and is designed to assist one 1.8-MW hydroelectric facility that is privately owned.

The commission declines to amend the definition of small producer and clarifies that this definition applies to all renewable energy facilities, not just hydropower. The offset methodology added in subsection (h) of this section will benefit existing hydropower facilities larger than two MW.

TXU proposed changing the definition of "renewable energy technology" to include those technologies that use a *de minimus* burning of fossil fuels. CSW agreed with TXU on this recommendation.

The commission declines to amend the definition of renewable energy technology in this section, as it is consistent with the definition set forth in PURA §39.904(d).

Shell suggested modifying the definition of "renewable energy credit" (REC) and "new resources" because the definitions as written are impermissible under the Commerce Clause.

The commission concludes that there is a risk that parties may challenge this rule on the grounds that it is impermissible under the Commerce Clause. The commission amends the definition of renewable energy credit in this section to reduce the likelihood of such a challenge. The commission concludes that all RECs, whether generated in Texas or elsewhere, must be physically metered in Texas and verifiable by the program administrator. In order to verify the output from a renewable source, the generator must demonstrate that the renewable energy actually reaches Texas. The intent of this requirement is to ensure that all RECs participating in the trading program represent actual megawatt-hours of renewable energy for consumption by Texas retail customers. Renewable facilities that deliver electricity into a transmission system where it is commingled with electricity from non-renewable resources could not be verified as delivered to Texas customers. In addition, the commission emphasizes that 2,000 MW of new renewable capacity shall be installed in Texas by January 1, 2009. Therefore, any capacity shortfalls that arise during the course of the program shall be made up in the REC allocation requirements for competitive retailers. The commission amends subsection (h) of this section to reflect this conclusion.

Comments on §25.173(d)

Shell Energy stated that the rule should require municipal utilities or cooperatives to bear a proportionate share of RECs upon opting in to competition during a compliance period.

The commission agrees with Shell and points out that this requirement is set out in subsection (d)(1) of this section. Therefore, no amendment is necessary.

Shell recommended that renewable generators alone pay program costs. The Coalition disagreed, stating that generators will interface with the program through the certification process, and it is perhaps appropriate that the costs associated with that process be paid by the generators. There may be other certification processes, the cost of which can be borne by the party seeking certification. In addition, costs associated with a specific transaction, such as REC transactions, can be assigned to the transacting parties. However, RECs are the core of the program, and the Coalition stated that it is most appropriate to allocate general program costs, as well as costs associated with allocating REC requirements and monitoring compliance, among REPs on the basis of market share.

The commission declines to apportion program cost responsibility among market participants in this section. The commission notes that this issue was never addressed in any of the technical "task force" meetings and should therefore be resolved under a separate proceeding related to the program administration function.

Comments on §25.173(e)

CPS noted, that while the rule as proposed does not necessarily prohibit the output from facilities meeting the requirements of PURA §39.904(f) from receiving renewable energy credits (RECs), §25.173(e) should be amended to specifically include such facilities.

The commission agrees with CPS and amends subsection (e) to clarify that facilities meeting the requirements of PURA §39.904(f) are eligible for participation in the trading program.

Duke Solar and Boeing Company strongly recommended modification of subsection (e) to ensure that the full range of industry-standard solar thermal technologies will be eligible to compete in the Texas renewable energy market. For a new renewable energy technology that operates principally on a non-combustible renewable resource, such as solar thermal or geothermal energy, and uses fossil fuel as a back-up or secondary fuel, credits may be earned only on the renewable portion of energy production.

The commission agrees with Duke Solar and Boeing Company's suggested language and amends subsection (e) to reflect that RECs produced by these types of facilities would be earned only on the renewable portion of energy production. The commission additionally amends subsection (e) to clarify that the capacity contribution toward meeting the capacity goals must be adjusted to reflect the percentage of energy that is produced by the secondary or back-up fuel.

Shell Energy noted that, while subsection (e)(2) prevents a resource's above-market costs from being included in the rates of any utility, municipally-owned utility, or distribution cooperative, the rule does not specify how to determine whether a resource's above-market costs were included in a utility's rates; nor does it define "above-market costs." Shell recommended amending the rule to provide that above-market costs include that portion of costs associated with a renewable energy resource that the owner can not reasonably recover from customers in a competitive retail or wholesale market. CSW proposed that "above-market costs" should be determined by comparing the costs of renewables with the costs of traditional fossil fuel resources.

The commission declines to accept Shell's proposed definition for the words "above-market costs." The commission concludes that the term "above-market costs" when referring to costs associated with new renewable energy facilities, is self-explanatory; they are the difference between the cost of these facilities and the cost of any other type of new generating facility. The commission declines to incorporate Shell's suggested definition into this section, as it is unnecessary.

The Coalition endorsed the requirement set forth in subsection (e)(2), and added that all resources owned or under contract with municipal utilities and distribution cooperatives should also be subject to this provision. The coalition explained that municipally owned utilities and distribution cooperatives not offering customer choice will not be subject to the same competitive discipline as REPs. Nor will they be subject to the type of rate review traditionally applied by the commission to fully regulated electric utilities. As a result, they may be able to allocate some of the above-market costs of their renewable-resource-based power to their captive retail customers, while reducing the prices of their renewable energy credits and thereby undercutting competing suppliers in the credits market. This would depress prices in the credits market and, in turn, dilute the incentive for competing developers to construct the new renewable generating facilities envisioned by the Legislature.

The commission agrees with the Coalition and points out that this requirement is already set out in subsection (e)(2) of this section. Therefore, no amendment is necessary.

The Coalition also recommended establishing a date certain to serve as a cutoff date for capacity additions at existing renewable-resource generating facilities allowed under subsection (e)(3). Capacity additions made prior to this date would not be eligible for the credits trading program.

The commission agrees with the Coalition that incremental capacity additions made prior to September 1, 1999 should not be allowed to participate in the trading program. The purpose of the trading program is to allocate the above-market costs associated with new renewable capacity in a least cost manner. The commission amends (c)(7) to reflect this conclusion.

TXU pointed out a slight inconsistency between two provisions concerning repowered facilities. Subsection (e) provides that only a qualifying existing resource, a new resource, or a small power producer is eligible to earn credits. TXU noted that a repowered facility does not fall within one of these categories. This is inconsistent with subsection (e)(3) allowing the energy produced by the incremental capacity from the repowering of existing renewable facilities to earn RECs. If the intent is to allow the energy associated with the incremental capacity obtained by repowering facilities to earn RECs, then §25.173(e) should be modified. CSW agreed with this change but added that the provision should be further revised to clarify that expansions of existing resources are also eligible to produce RECs in the trading program.

The commission agrees with TXU and CSW and amends subsection (c)(7) to include incremental capacity and its associated energy in the definition of a new resource. New resources are eligible to produce RECs in the trading program; additional changes to subsection (e) are therefore not necessary.

Comments on §25.173(f)

OPC and Cities opposed the exclusion of renewable energy capacity additions associated with an emissions reductions project under Health and Safety Code §382.01593, stating that PURA does not require an exclusion of such capacity additions. In fact, the prohibition preventing renewable energy capacity from qualifying for both programs is likely to reduce or even eliminate the possibility that renewable resources would be built to meet the requirements of the Health and Safety Code. Instead, the commission should use every opportunity to encourage utilities to reduce emissions and improve air quality through the installation of new renewable energy technology. EDF contended that the clean air provisions of SB 7 including this renewable energy program were contemplated separate from the renewable energy option in Senate Bill 766 (SB 766), Act of May 30, 1999, 76th Legislature, Regular session, chapter 406, 1999 Texas Session Law Service 2626, 2628 (Vernon) (to be codified as an amendment to Health and Safety Code §382.05193) relating to emissions reductions projects. Double-counting a "grandfathered" facility's requirements under Health and Safety Code §382.05193 and PURA §39.904 does just the opposite, it would diminish the clean air benefits contained in SB 7 and SB 766. CSW disagreed with EDF's position. The Coalition agreed with EDF, reporting that it has submitted comments in a rulemaking proceeding of the Texas Natural Resources Conservation Commission (TNRCC) regarding modifications to its rules implementing SB 766. In those comments, the Coalition supported a corresponding prohibition on units of output from renewable-resource facilities being simultaneously eligible for both (1) the credits trading program established to implement the renewables mandate of SB 7 and (2) the TNRCC's emission reduction credit program established under SB 766.

The commission agrees with EDF and the Coalition that the provisions contained in SB 7 and SB 766 are two separate programs relating to the policy of cleaner air for Texas citizens. Allowing a company to satisfy two requirements by complying with a single project would reduce the overall deployment of these resources and associated goal of cleaner air. The commission also points out that the language contained in subsection (f)(1) is consistent with language contained in the rulemaking currently underway at the TNRCC. No amendment to this subsection is therefore necessary.

OPC and Cities, TXU, and CSW opposed the prohibition against counting capacity generated by an existing fossil plant repowered to use renewable fuel, stating that a former fossil fuel plant that is converted to burn renewable fuel is essentially new generating capacity from renewable energy technologies and should count toward the goal in PURA §39.904. These parties contended that such conversions may be among the most cost-effective way to achieve the goal because the avoided capital expenses could be substantial. Furthermore, such a site already has access to the transmission and distribution network and may even possess all the required permitting. EDF argued that the point of the legislation is to provide for new capital investment. Opportunities such as fossil repowering and its close cousin, co-firing, allow arbitrage opportunists to make minimal capital investments to earn credits that do nothing to increase economic development in Texas by providing jobs, producing new equipment for use in Texas, or providing the deployment levels that cause renewable energy costs to go down. The Coalition agreed with EDF, stating that allowing bio-fuels to replace fossil fuel in existing generators to be eligible for RECs would displace and preclude the development of new renewable capacity and violate SB 7's mandate for the development of 2000 megawatts of new renewable capacity

The commission agrees with EDF and the Coalition that one purpose of the trading program is to provide an incentive for new capital investment in cleaner energy technologies. The commission points out that all existing renewable facilities are not eligible to participate in the trading program. One reason for this is that existing facilities have enjoyed cost recovery. This is true for existing fossil fuel facilities; they too have enjoyed cost recovery over the years. The commission also notes that during the task force meetings, not one party was able to adequately explain the process by which an existing fossil fuel facility is repowered to become a renewable facility or the capital costs associated with this repowering concept. Without this type of cost data, it would be difficult to concur with OPC and Cities that allowing repowered fossil fuel facilities participation in the program would be a more cost effective way to fulfill the 2,000 MW requirement. The commission declines to amend subsection (f)(2) allowing these types of facilities to participate in the trading program.

Comments on §25.173(g)

Shell Energy proposed that this subsection should specify the program administrator's funding source, independence, selection process, and whether the parties under its jurisdiction may appeal decisions to the commission. Shell also recommended a requirement that the program administrator undergo an independent audit every two years, both of its own expenses and of all REC accounts. CSW agreed with Shell Energy's proposals with respect to program independence, audits and appeals changes but does not agree with the selection process changes. This type of selection process takes too much time. The majority of the parties have already expressed that the ISO is well suited to take on this responsibility. The Coalition commended Shell for offering a number of useful recommendations with respect to the Program Administrator's status and responsibilities. These included audits of generators and the Program Administrator, appeal procedures for program administrator actions, and the necessity to keep the Program Administrator independent of program participants. The Coalition and CSW agreed with Shell that REC account status information be kept confidential. This is consistent with the Coalition's recommendation that REC transactions, including prices, should not be recorded. Shell recommended that the Program Administrator provide regular information on total statewide retail sales, in order that REPs be able to predict their market share, and thus their REC requirements. The Coalition, CSW, Reliant, and TXU agreed that such information will be very useful to program participants, particularly retail providers. The Coalition added that performance information of renewable energy systems and technologies, both those installed and participating in the program and those anticipated projects would be valuable information for competitive retailers. The Coalition recommended that the program administrator assess penalties to competitive retailers for non-compliance. TXU disagreed with this concept, stating that the authority to assess penalties lies with the commission. CSW recommended that competitive retailers not in compliance with the trading program should not be reported to the commission as required pursuant to this subsection.

The commission commends Shell for providing useful suggestions that will help ensure effective operation of the trading program, which will benefit all market participants. The commission amends subsection (g) to incorporate Shell's suggested language pertaining to appeals, audits, confidentiality, and program administrator functions. However, as noted previously, cost responsibility and the program administrator selection process will be addressed under a separate proceeding. The commission agrees with TXU that the commission, not the program administrator, should assess the penalties. This is consistent with the language set forth in subsection (o) of this section. The commission declines to accept CSW's proposed change that would eliminate the reporting of non-compliant competitive retailers to the commission. The commission concludes that this type of information is necessary and will assist the commission in enforcing this section.

Comments on §25.173(h)

Enron suggested language clarifying that providers of last resort would be subject to the requirements of this section. CSW disagreed with Enron's proposed revision, stating that it is unnecessary because the term "retail electric provider" is already defined to include the provider of last resort.

The commission agrees with CSW that this change is unnecessary; PURA §31.002(17) defines a retail electric provider as a person that sells electric energy to retail customers in Texas. A provider of last resort is therefore by definition a REP; no amendment to this subsection is necessary.

Comments on §25.173(i)

Shell proposed that the rule should require the program administrator to use generation data that the generation facility reports to NERC's Generation Availability Data System ("GADS") program in evaluating the "actual generator performance data." Almost all generators report their performance to NERC, which compiles the Generation Availability Report ("GAR"), used by utilities, regulators and others for a variety of purposes. In general, the Coalition supported the methodology for calculating the capacity conversion factor set forth in the Rule. The Coalition supported the use of actual performance data as the basis of the CCF, although it is important for the commission also to reserve for itself, as it appears to have done implicitly in subsection (i)(2)(D), the authority to make adjustments as necessary to achieve the statutory goals. As the profile of new renewable-resource generating projects participating in the credits program changes over time, performance of new projects may vary from the historical performance of operating projects. Thus, it may not be possible to precisely project the performance characteristics of the next block of capacity using only the historical data of operating projects. Some judgment may be called for to make this projection more accurately, so as to enhance the likelihood of achieving the targeted amount of capacity.

The Coalition also recommended the use of whole-year periods of actual performance data as the basis for recalculating the CCF. This is particularly important when the generating facilities are wind-powered. While inter-annual variation in the wind and solar resources is modest, seasonal or intra-annual variations can be significant. Thus it is critical to include four consecutive seasons (one full year) in sampling periods. For this reason, it may not be practical to recalculate the CCF in the fourth quarter of 2003, as set forth in subsection (i)(2). The Coalition preferred a readjustment in the first quarter of 2003, even though it would be based on only one year of performance. Twelve months' performance data is acceptable as a minimum basis for this calculation, as indicated in subsection (i)(2)(A). And doing so at that point would give REPs an additional three-quarters in which to adjust their contractual arrangements, as needed, before the compliance period begins.

TXU strongly disagreed with the Coalition's suggestion that the CCF be readjusted after the program's first compliance period. TXU maintained that only one year of data will not provide a reasonable approximation of likely average capacity factors. Forced outages, unusual weather, and transmission constraints may all impact energy production in 2002. At least two years, if not three years, is much more likely to produce a reasonable figure. TXU commented that the initial CCF of 35% is too high, but provides a necessary degree of certainty and should apply for three years, not two. TXU agreed in principle with the Coalition that the CCF should be recalculated during the first quarter of a compliance period, not the fourth. CSW opposed TXU's proposed changes, maintaining that the language proposed in this subsection should remain as written. CSW explained that there will be at least four years of data that could be applied towards the CCF calculation if the 1999 wind projects, totaling approximately 150 MW, are included in the data set. Waiting three years could result in missing the legislative targets on either the high or low side.

The commission notes that an accurate CCF is fundamental to successful implementation of PURA §39.904. An accurate CCF helps to ensure that the capacity targets are achieved in a timely and efficient manner. An administratively set CCF of 35% for the first two compliance periods, followed by biennial readjustments based on actual facility performance data, will ensure that the capacity targets are met in an efficient manner. The commission notes that this issue was painstakingly discussed and negotiated in the "task-force" meetings as part of a comprehensive program design package. The commission therefore declines to accept the changes to this subsection as requested by TXU, Shell, or the Renewable Coalition.

Comments on §25.173(j)

Shell Energy recommended that this subsection should more clearly state that competitive retailers and others may trade RECs. Uncertainty may hamper trading activities and defeat the proposed rule's and the statute's goals. Shell also recommended that the trading program should ensure anonymity in the trading process. For example, the EPA has delegated the SO_2 allowance auction responsibility to the Chicago Board of Trade, which conducts annual auctions of both allowances that EPA has held in reserve and those that private parties have offered for sale. Such a system could allow competitive retailers to trade RECs without fear that entities will gain a market power advantage in trading. Shell also maintained that the rule also should expressly permit several commercially recognized types of transactions. First, it should expressly allow parties to enter into long-term contracts to sell their surplus RECs. Second, it should allow a futures market, where entities agree to sell RECs in given forward periods. The EPA's Acid Rain Rules permit trades in future allowances. Finally, the commission should expand the trading program to allow entities other than competitive retailers, such as brokers, to trade RECs. This latter provision addresses the fear some parties have expressed that an entity might corner the market on RECs. The more entities that can trade RECs, the less likely that any one entity can "corner the market."

The Coalition agreed with Shell that the rule should explicitly make allowance in the REC trading program for a multiplicity of types of transactions and market participants. The Coalition disagreed with Shell's proposal that the commission should establish a trading/auction system. The Coalition recommended commission intervention only in the event that effective market mechanisms fail to develop of their own accord. TXU did not agree that any of Shell's proposals were necessary.

The commission declines to incorporate Shell's suggestion, noting that such types of transactions are not prohibited under this section. The transactions listed by Shell would be permissible in this trading program.

Shell proposed that the rule should provide for "rounding", stating that a generator producing 0.5 MWh or greater as its last unit generated should be awarded one REC. Doing so will recognize and reward production at the margins, and will especially benefit small producers. TXU agreed with Shell, clarifying that this was the intent of the parties during the workshops, and including an explicit rounding provision in the rule would be appropriate.

The commission agrees with this change, noting that this was the intent of the parties during the task-force meetings. The commission amends subsection (k)(1) to reflect this conclusion.

Comments on §25.173(m)

Shell proposed that the word "periodic" be eliminated from this subsection because one might interpret the word as limiting the times the commission may inspect a facility. Shell also recommended additional language that would clarify that, in the event that decertification occurs, RECs awarded prior to decertification remain valid. The Coalition, CSW and TXU agreed with this change.

The commission agrees with Shell and amends subsection (m) to reflect this conclusion.

Comments on proposed forms

The Coalition and CPS proposed minor modifications to the form to accommodate multiple unit wind facilities and landfill gas facilities. These changes were incorporated into the certification form.

General Comments

The commission received comments regarding the effect of the rule on interstate commerce. ETC argued that the limitation to renewables installed in Texas is a violation of the Commerce Clause, in Article 1, Section 8 of the United States Constitution. ETC contended that the proposed rule's exclusion of out-of-state renewables from the credit trading program or from the required allocation imposed on each REP, MOU, and electric cooperative violates the Commerce Clause, because it treats in-state economic interests more favorably than their out-of-state counterparts. ETC argued that the proposed rule creates a clear, unmistakable preference for in-state renewable resources solely on the basis of their physical location, without regard for the fact that renewable generation sold in Texas by Texas companies for use by Texas consumers furthers the goal of cleaner air in Texas regardless of its origin. ETC maintained that, if the ultimate purpose of the renewables mandate is to provide for cleaner air in Texas, as opposed to creating a market, then the proposed rule should recognize all renewable resources that result in energy sold in Texas, regardless of their origin.

STEC agreed with ETC that the exclusion of out-of-state renewables in the trading program is unconstitutional because it places an impermissible burden on interstate commerce; however, OPC and Cities disagreed with ETC, stating that the proposed rule accurately reflects the intent of PURA §39.904.

Shell commented that the REC definition, which requires a retailer to purchase renewable energy generated in Texas, violates Constitutional prohibitions against a state discriminating against out-of-state commerce. Shell argued that the Commerce Clause prohibits states from engaging in economic protectionism against other states, and that state statutes discriminating against out-of-state commerce are constitutional only if justified by a valid factor unrelated to economic protectionism. Shell asserted that the proposed rule discriminates against out-of-state commerce by requiring competitive retailers to purchase a portion of their energy supplies from Texas sources. Shell interpreted the statute as not requiring competitive retailers to purchase their renewable energy requirement from Texas sources. Shell recommended that the commission allow a retailer to meet its renewable energy requirement by purchasing either Texas or out-of-state renewable energy, while applying the same performance standards to out-of-state suppliers under subsection (e). Shell further noted that line losses and transmission constraints will lead most potential suppliers to locate in Texas anyway, therefore a modified rule will lead to more renewable energy capacity in Texas without violating the Constitution.

The Renewable Coalition disagreed with ETC and Shell, contending that state statutes distinguishing between in-state and out-of-state interests are constitutional if justified by a valid factor unrelated to economic protectionism. In the case of the renewable energy mandate, the legitimate local purpose of §39.904 is the Legislature's desire to capture and develop, rather than neglect and lose, the environmental benefits gained from using Texas' vast, untapped store of renewable resources. This legitimate public purpose can not be furthered without "installing in Texas" the renewable facilities at those sites in Texas where the resources are located; it was not the Legislature's intent to be protectionist.

The Coalition also stated that any person in the country is free to participate in the development of these renewable capacity additions. The Coalition commented that allowing renewable resources from outside of Texas to qualify would totally disconnect the implementation of the statute and rule from the legitimate objectives of the program as conceived by the Legislature. EDF generally concurred with the statements made by the Coalition.

The proposed rule as published is permissible under the commerce clause. The object of the proposed rule was the entirely legitimate goal of improving the air quality for Texas citizens, and the rule was crafted to achieve this goal through efficient and economical development of local renewable resources for the local generation of clean energy. The commission has modified the rule, however, by removing the exclusion of out-of-state renewable resources. The purpose of this modification is to reduce the risk that implementation of this statutory program would be delayed by a commerce-clause challenge to the rule. Beyond the clean-air benefits, the rule provides incentives for the development of an abundant natural resource. The commission finds that the means for achieving these goals are reasonable and do not unfairly discriminate against other states through economic favoritism.

The federal Clean Air Act is implemented through state plans that focus on emissions in local areas. Texas has several areas that are not in compliance with the Clean Air Act standards, including Dallas-Fort Worth, Houston, Corpus Christi, and Beaumont-Port Arthur, and areas that are nearing nonattainment, such as Austin and San Antonio. To help meet the Clean Air Act standards, specific provisions of Senate Bill 7 require the clean-up of plants with high emissions, and the use of clean-burning fossil fuels, such as natural gas, and the use of renewable resources. Cleaning the air in Texas, however, has significant associated costs, and the state agency responsible for preparing implementation plans is in the process of developing a laundry list of air clean-up measures that will affect a number of industries.

New renewable resources, although potentially more expensive than other electric resources, are an effective means for cleaning the air. Through PURA §39.904, the legislature clearly sought to support the development of renewable resources in Texas to efficiently and economically reduce emissions from electricity generation. The demand for electricity in Texas has been and is projected to continue to increase, and the legislature mandated the use of energy derived from renewable resources in Texas so that a portion of the additional future energy generated and consumed by Texans would result in cleaner air for all Texans.

The commission acknowledges the local economic benefits that incidentally result from the rule and concludes that it is permissible for the state, under its sovereign powers, to use markets and market forces to achieve environmental benefits for its citizens. The rule is not a measure for economic protectionism, but, rather, a legitimate program that is consistent with state and federal goals under the Clean Air Act, and is consistent with the mechanism (state action) that is at the heart of the Clean Air Act.

While the commission believes that the rule, as originally proposed, was consistent with the Commerce Clause, it is modifying the rule to reduce the risk of a constitutional challenge. Renewable facilities would qualify for RECs if the output of the renewable facility reaches Texas, so that it can be physically metered and verified in Texas. It is anticipated and intended that the rule will encourage the development of renewable resources within Texas. Renewable resources are distinctly different from coal or natural gas. The wind and solar energy not captured and used today vanishes and can not be recovered. In addition, they are distinctly different in their ability to be transported. Coal and gas can be transported to a suitable location for conversion to electricity, but most renewable resources must be exploited where they are found. Texas has a vast untapped array of renewable resources available for the clean generation of energy. Using these resources will improve the air quality, yet their environmental benefits are wasted unless they are exploited. Clean generation of electricity outside of Texas also may provide environmental benefits if it is located close to Texas and serves Texas consumers, but it is difficult to draw a line between a location that would and would not benefit Texas air. The rule therefore, allows credits to be accorded to all new facilities located out of the state as long as the energy produced by those facilities meets the eligibility requirements of the rule and is physically metered and verified in Texas.

Any local economic benefits that may result from the state's development of new renewable capacity are incidental to the legitimate goal of providing cleaner air for Texans and developing Texas renewable resources. To foster the development of renewable generation plants in Texas, it is necessary to create incentives. PURA §39.904(c)(2)(B) specifically requires the commission to encourage development, construction, and operation of new renewable energy projects in this state to bring the environmental benefits of clean air to Texas. The rule accomplishes this objective without impeding the flow of interstate commerce.

EDF pointed out that the provisions in this section are interrelated, noting that each commission decision on individual provisions can tend to either promote development of renewable capacity slightly earlier, or to retard development of resources to meet the interim legislative goals. EDF added that decisions were already made in the legislative process to accommodate risk and cost issues raised by utilities. These accommodations have had the effect of delaying and back-loading the acquisition of new renewables relative to a simple and consistent proposal that would have developed 200 MWs of new renewable energy each year for ten years. EDF provided a table illustrating that the graduated increase of new renewables as required in PURA §39.904(a) provided 50% less reduction when compared with a simple program that would have required 200 MW of new renewable energy each year for ten years.

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting this section, the commission makes other minor modifications for the purpose of clarifying its intent.

This new section is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998) (PURA), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction, and specifically, Senate Bill 7, Act of May 21, 1999, 76th Legislature, Regular Session, chapter 405, 1999 Texas Session Law Service, 2543, 2558 (Vernon) (to be codified as an amendment to the Public Utility Regulatory Act, Texas Utilities Code Annotated §39.101(b)(3) and §39.904) which entitles all customers access to providers of renewable energy, requires an additional 2,000 MW of renewable generating capacity to be installed in Texas by 2009, directs the commission to establish a renewable energy credits trading program and to adopt rules necessary to enforce and administer the program outlined in this section.

Cross Reference to Statutes: Public Utility Regulatory Act §§11.002(a), 14.001, 14.002, 39.101(b)(3), and 39.904.

§25.173. Goal for Renewable Energy.

(a) Purpose. The purpose of this section is to ensure that an additional 2,000 megawatts (MW) of generating capacity from renewable energy technologies is installed in Texas by 2009 pursuant to the Public Utility Regulatory Act (PURA) §39.904, to establish a renewable energy credits trading program that would ensure that the new renewable energy capacity is built in the most efficient and economical manner, to encourage the development, construction, and operation of new renewable energy resources at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial resources, to protect and enhance the quality of the environment in Texas through increased use of renewable resources, to respond to customers' expressed preferences for renewable resources by ensuring that all customers have access to providers of energy generated by renewable energy resources pursuant to PURA §39.101(b)(3), and to ensure that the cumulative installed renewable capacity in Texas will be at least 2,880 MW by January 1, 2009.

(b) Application. This section applies to power generation companies as defined in §25.5 of this title (relating to definitions), and competitive retailers as defined in subsection (c) of this section. This section shall not apply to an electric utility subject to PURA §39.102(c) until the expiration of the utility's rate freeze period.

(c) Definitions.

(1) Competitive retailer–A municipally-owned utility, generation and transmission cooperative (G&T), or distribution cooperative that offers customer choice in the restructured competitive electric power market in Texas or a retail electric provider (REP) as defined in §25.5 of this title.

(2) Compliance period–A calendar year beginning January 1 and ending December 31 of each year in which renewable energy credits are required of a competitive retailer.

(3) Designated representative–A responsible natural person authorized by the owners or operators of a renewable resource to register that resource with the program administrator. The designated representative must have the authority to represent and legally bind the owners and operators of the renewable resource in all matters pertaining to the renewable energy credits trading program.

(4) Early banking–Awarding renewable energy credits (RECs) to generators for sale in the trading program prior to the program's first compliance period.

(5) Existing facilities–Renewable energy generators placed in service before September 1, 1999.

(6) Generation offset technology–Any renewable technology that reduces the demand for electricity at a site where a customer consumes electricity. An example of this technology is solar water heating.

(7) New facilities–Renewable energy generators placed in service on or after September 1, 1999. A new facility includes the incremental capacity and associated energy from an existing renewable facility achieved through repowering activities undertaken on or after September 1, 1999.

(8) Off-grid generation–The generation of renewable energy in an application that is not interconnected to a utility transmission or distribution system.

(9) Program administrator–The entity approved by the commission that is responsible for carrying out the administrative responsibilities related to the renewable energy credits trading program as set forth in subsection (g) of this section.

(10) REC offset (offset)–An REC offset represents one MWh of renewable energy from an existing facility that may be used in place of an REC to meet a renewable energy requirement imposed under this section. REC offsets may not be traded, shall be calculated as set forth in subsection (i) of this section, and shall be applied as set forth in subsection (h) of this section.

(11) Renewable energy credit (REC or credit)–An REC represents one megawatt hour (MWh) of renewable energy that is physically metered and verified in Texas and meets the requirements set forth in subsection (e) of this section.

(12) Renewable energy credit account (REC account)–An account maintained by the renewable energy credits trading program administrator for the purpose of tracking the production, sale, transfer, purchase, and retirement of RECs by a program participant.

(13) Renewable energy credits trading program (trading program)–The process of awarding, trading, tracking, and submitting RECs as a means of meeting the renewable energy requirements set out in subsection (d) of this section.

(14) Renewable energy resource (renewable resource)–A resource that produces energy derived from renewable energy technologies.

(15) Renewable energy technology–Any technology that exclusively relies on an energy source that is naturally regenerated over a short time and derived directly from the sun, indirectly from the sun, or from moving water or other natural movements and mechanisms of the environment. Renewable energy technologies include those that rely on energy derived directly from the sun, on wind, geothermal, hydroelectric, wave, or tidal energy, or on biomass or biomass-based waste products, including landfill gas. A renewable energy technology does not rely on energy resources derived from fossil fuels, or waste products from inorganic sources.

(16) Repowering–Modernizing or upgrading an existing facility in order to increase its capacity or efficiency.

(17) Settlement period–The first calendar quarter following a compliance period in which the settlement process for that compliance year takes place.

(18) Small producer–A renewable resource that is less than two megawatts (MW) in size.

(d) Renewable energy credits trading program (trading program). Renewable energy credits may be generated, transferred, and retired by renewable energy power generators, competitive retailers, and other market participants as set forth in this section.

(1) The program administrator shall apportion a renewable resource requirement among all competitive retailers as a percentage of the retail sales of each competitive retailer as set forth in subsection (h) of this section. Each competitive retailer shall be responsible for retiring sufficient RECs as set forth in subsections (h) and (k) of this section to comply with this section. The requirement to purchase RECs pursuant to this section becomes effective on the date each competitive retailer begins serving retail electric customers in Texas.

(2) A power generating company may participate in the program and may generate RECs and buy or sell RECs as set forth in subsection (j) of this section.

(3) RECs shall be credited on an energy basis as set forth in subsection (j) of this section.

(4) Municipally-owned utilities and distribution cooperatives that do not offer customer choice are not obligated to purchase RECs. However, regardless of whether the municipally-owned utility or distribution cooperative offers customer choice, a municipally-owned utility or distribution cooperative possessing renewable resources that meet the requirements of subsection (e) of this section may sell RECs generated by such a resource to competitive retailers as set forth in subsection (j) of this section.

(5) Except where specifically stated, the provisions of this section shall apply uniformly to all participants in the trading program.

(e) Facilities eligible for producing RECs in the renewable energy credits trading program. For a renewable facility to be eligible to produce RECs in the trading program it must be either a new facility or a small producer as defined in subsection (c) of this section and must also meet the requirements of this subsection:

(1) A renewable energy resource must not be ineligible under subsection (f) of this section and must register pursuant to subsection (n) of this section;

(2) The facility's above-market costs must not be included in the rates of any utility, municipally-owned utility, or distribution cooperative through base rates, a power cost recovery factor (PCRF), stranded cost recovery mechanism, or any other fixed or variable rate element charged to end users;

(3) For a renewable energy technology that requires fossil fuel, the facility's use of fossil fuel must not exceed 2.0% of the total annual fuel input on a British thermal unit (BTU) or equivalent basis;

(4) The output of the facility must be readily capable of being physically metered and verified in Texas by the program administrator. Energy from a renewable facility that is delivered into a transmission system where it is commingled with electricity from non-renewable resources can not be verified as delivered to Texas customers. A facility is not ineligible by virtue of the fact that the facility is a generation-offset, off-grid, or on-site distributed renewable facility if it otherwise meets the requirements of this section; and

(5) For a municipally owned utility operating a gas distribution system, any production or acquisition of landfill gas that is directly supplied to the gas distribution system is eligible to produce RECs based upon the conversion of the thermal energy in BTUs to electric energy in kWh using for the conversion factor the systemwide average heat rate of the gas-fired units of the combined utility's electric system as measured in BTUs per kWh.

(6) For industry-standard thermal technologies, the RECs can be earned only on the renewable portion of energy production. Furthermore, the contribution toward statewide renewable capacity megawatt goals from such facilities would be equal to the fraction of the facility's annual MWh energy output from renewable fuel multiplied by the facility's nameplate MW capacity.

(f) Facilities not eligible for producing RECs in the renewable energy credits trading program. A renewable facility is not eligible to produce RECs in the trading program if it is:

(1) A renewable energy capacity addition associated with an emissions reductions project described in Health and Safety Code §382.05193, that is used to satisfy the permit requirements in Health and Safety Code §382.0519;

(2) An existing facility that is not a small producer as defined in subsection (c) of this section; or

(3) An existing fossil plant that is repowered to use a renewable fuel.

(g) Responsibilities of program administrator. No later than June 1, 2000, the commission shall approve an independent entity to serve as the trading program administrator. At a minimum, the program administrator shall perform the following functions:

(1) Create accounts that track RECs for each participant in the trading program;

(2) Award RECs to registered renewable energy facilities on a quarterly basis based on verified meter reads;

(3) Assign offsets to competitive retailers on an annual basis based on a nomination submitted by the competitive retailer pursuant to subsection (n) of this section;

(4) Annually retire RECs that each competitive retailer submits to meet its renewable energy requirement;

(5) Retire RECs at the end of each REC's three-year life;

(6) Maintain public information on its website that provides trading program information to interested buyers and sellers of RECs;

(7) Create an exchange procedure where persons may purchase and sell RECs. The exchange shall ensure the anonymity of persons purchasing or selling RECs. The program administrator may

delegate this function to an independent third party. The commission shall approve any such delegation;

(8) Make public each month the total energy sales of competitive retailers in Texas for the previous month;

(9) Perform audits of generators participating in the trading program to verify accuracy of metered production data;

(10) Allocate the renewable energy responsibility to each competitive retailer in accordance with subsection (h) of this section; and

(11) Submit an annual report to the commission. Beginning with the program's first compliance period, the program administrator shall submit a report to the commission on or before April 15 of each calendar year. The report shall contain information pertaining to renewable energy power generators and competitive retailers. At a minimum, the report shall contain:

(A) the amount of existing and new renewable energy capacity in MW installed in the state by technology type, the owner/operator of each facility, the date each facility began to produce energy, the amount of energy generated in megawatt-hours (MWh) each quarter for all capacity participating in the trading program or that was retired from service; and

(B) a listing of all competitive retailers participating in the trading program, each competitive retailer's renewable energy credit requirement, the number of offsets used by each competitive retailer, the number of credits retired by each competitive retailer, a listing of all competitive retailers that were in compliance with the REC requirement, a listing of all competitive retailers that failed to retire sufficient REC requirement, and the deficiency of each competitive retailer that failed to retire sufficient RECs to meet its REC requirement.

(h) Allocation of REC purchase requirement to competitive retailers. The program administrator shall allocate REC requirements among competitive retailers. Any renewable capacity that is retired before January 1, 2009 or any capacity shortfalls that arise due to purchases of RECs from out-of-state facilities shall be replaced and incorporated into the allocation methodology set forth in this subsection. Any changes to the allocation methodology to reflect replacement capacity shall occur two compliance periods after which the facility was retired or capacity shortfall occurred. The program administrator shall use the following methodology to determine the total annual REC requirement for a given year and the final REC requirement for individual competitive retailers:

(1) The total statewide REC requirement for each compliance period shall be calculated in terms of MWh and shall be equal to the renewable capacity target multiplied by 8,760 hours per year, multiplied by the appropriate capacity conversion factor set forth in subsection (i) of this section. The renewable energy capacity targets for the compliance period beginning January 1, of the year indicated shall be:

(A) 400 MW of new resources in 2002;

(B) 400 MW of new resources in 2003;

(C) 850 MW of new resources in 2004;

(D) 850 MW of new resources 2005;

(E) 1,400 MW of new resources in 2006;

(F) 1,400 MW of new resources in 2007;

(G) 2,000 MW of new resources in 2008; and

(H) 2,000 MW of new resources in 2009 through 2019.

(2) The final REC requirement for an individual competitive retailer for a compliance period shall be calculated as follows:

(A) Each competitive retailer's preliminary REC requirement is determined by dividing its total retail energy sales in Texas by the total retail sales in Texas of all competitive retailers, and multiplying that percentage by the total statewide REC requirement for that compliance period.

(B) The adjusted REC requirement for each competitive retailer that is entitled to an offset is determined by reducing its preliminary REC requirement by the offsets to which it qualifies, as determined under subsection (i) of this section, with the maximum reduction equal to the competitive retailer's preliminary REC requirement. The total reductions for all competitive retailers is equal to the total usable offsets for that compliance period.

(C) Each competitive retailer's final REC requirement for a compliance period shall be increased to recapture the total usable offsets calculated under subparagraph (B) of this paragraph. The additional REC requirement shall be calculated by dividing the competitive retailer's adjusted REC requirement by the total adjusted REC requirement of all competitive retailers. This fraction shall be multiplied by the total usable offsets for that compliance period and this amount shall be added to the competitive retailer's adjusted REC requirement to produce the competitive retailer's final REC requirement for the compliance period.

(i) Nomination and calculation of REC offsets.

(1) A REP, municipally-owned utility, G&T cooperative, distribution cooperative, or an affiliate of a REP, municipally-owned utility, or distribution cooperative, may apply offsets to meet all or a portion of its renewable energy purchase requirement, as calculated in subsection (h) of this section, only if those offsets are nominated in a filing with the commission by June 1, 2001. A G&T may nominate the combined offsets for itself and its member distribution cooperatives upon the presentation of a resolution by its Board authorizing it to do so.

(2) The commission shall verify any designations of REC offsets and notify the program administrator of its determination by December 31, 2001.

(3) REC offsets shall be equal to the average annual MWh output of an existing resource for the years 1991-2000 or the entire life of the existing resource, whichever is less.

(4) REC offsets qualify for use in a compliance period under subsection (h) of this section only to the extent that:

(A) The resource producing the REC offset has continuously since September 1, 1999 been owned by or its output has been committed under contract to a utility, municipally-owned utility, or cooperative nominating the resource under paragraph (1) of this subsection or, if the resource has been committed under a contract that expired after September 1, 1999 and before January 1, 2002, it is owned by or its output has been committed under contract to a utility, municipally-owned utility, or cooperative on January 1, 2002; and

(B) The facility producing the REC offsets is operated and producing energy during the compliance period in a manner consistent with historic practice.

(5) If the production from a facility producing the REC offset energy ceases for any reason, the competitive retailer may no longer claim the REC offset against its REC requirement.

(j) Calculation of capacity conversion factor. The capacity conversion factor used by the program administrator to allocate credits to competitive retailers shall be calculated as follows:

(1) The capacity conversion factor (CCF) shall be administratively set at 35% for 2002 and 2003, the first two compliance periods of the program.

(2) During the fourth quarter of the second compliance year (2003), the CCF shall be readjusted to reflect actual generator performance data associated with all renewable resources in the trading program. The program administrator shall adjust the CCF every two years thereafter and shall:

(A) be based on all renewable energy resources in the trading program for which at least 12 months of performance data is available;

(B) represent a weighted average of generator performance;

(C) use all valid performance data that is available for each renewable resource; and

(D) ensure that the renewable capacity goals are attained.

(k) Production and transfer of RECs. The program administrator shall administer a trading program for renewable energy credits in accordance with the requirements of this subsection.

(1) A REC will be awarded to the owner of a renewable resource when a MWh is metered at that renewable resource. A generator producing 0.5 MWh or greater as its last unit generated should be awarded one REC on a quarterly basis. The program administrator shall record the amount of metered MWh and credit the REC account of the renewable resource that generated the energy on a quarterly basis.

(2) The transfer of RECs between parties shall be effective only when the transfer is recorded by the program administrator.

(3) The program administrator shall require that RECs be adequately identified prior to recording a transfer and shall issue an acknowledgement of the transaction to parties upon provision of adequate information. At a minimum, the following information shall be provided:

(A) identification of the parties;

(B) REC serial number, REC issue date, and the renewable resource that produced the REC;

(C) the number of RECs to be transferred; and

(D) the transaction date.

(4) A competitive retailer shall surrender RECs to the program administrator for retirement from the market in order to meet its REC allocation for a compliance period. The program administrator will document all REC retirements annually.

(5) On or after each April 1, the program administrator will retire RECs that have not been retired by competitive retailers and have reached the end of their three-year life.

(6) The program administrator may establish a procedure to ensure that the award, transfer, and retirement of credits are accurately recorded.

(l) Settlement process. Beginning in January 2003, the first quarter following the compliance period shall be the settlement period during which the following actions shall occur:

(1) By January 31, the program administrator will notify each competitive retailer of its total REC requirement for the previous compliance period as determined pursuant to subsection (h) of this section.

(2) By March 31, each competitive retailer must submit credits to the program administrator from its account equivalent to its REC requirement for the previous compliance period. If the competitive retailer has insufficient credits in its account to satisfy its obligation, and this shortfall exceeds the applicable deficit allowance as set forth in subsection (m)(2) of this section, the competitive retailer is subject to the penalty provisions in subsection (o) of this section.

(m) Trading program compliance cycle.

(1) The first compliance period shall begin on January 1, 2002 and there will be 18 consecutive compliance periods. Early banking of RECs is permissible and may commence no earlier than July 1, 2001. The program's first settlement period shall take place during the first quarter of 2003.

(2) A competitive retailer may incur a deficit allowance equal to 5.0% of its REC requirement in 2002 and 2003 (the first two compliance periods of the program). This 5.0% deficit allowance shall not apply to entities that initiate customer choice after 2003. During the first settlement period, each competitive retailer will be subject to a penalty for any REC shortfall that is greater than 5.0% of its REC requirement under subsection (h) of this section. During the second settlement period, each competitive retailer will be subject to the penalty process for any REC shortfall greater than 5.0% of the second year REC allocation. All competitive retailers incurring a 5.0% deficit pursuant to this subsection must make up the amount of RECs associated with the deficit in the next compliance period.

(3) The issue date of RECs created by a renewable energy resource shall coincide with the beginning of the compliance year in which the credits are generated. All RECs shall have a life of three compliance periods, after which the program administrator will retire them from the trading program.

(4) Each REC that is not used in the year of its creation may be banked and is valid for the next two compliance years.

(5) A competitive retailer may meet its renewable energy requirements for a compliance period with RECs issued in or prior to that compliance period which have not been retired.

(n) Registration and certification of renewable energy facilities. The commission shall register and certify all renewable facilities that will produce either REC offsets or RECs for sale in the trading program. To be awarded RECs or REC offsets, a power generator must complete the registration process described in this subsection. The program administrator shall not award offsets or credits for energy produced by a power generator before it has been certified by the commission.

(1) The designated representative of the generating facility shall file an application with the commission on a form approved by the commission for each renewable energy generation facility. At a minimum, the application shall include the location, owner, technology, and rated capacity of the facility and shall demonstrate that the facility meets the resource eligibility criteria in subsection (e) of this section.

(2) No later than 30 days after the designated representative files the certification form with the commission, the commission shall inform both the program administrator and the designated representative whether the renewable facility has met the certification

requirements. At that time, the commission shall either certify the renewable facility as eligible to receive either RECs or offsets, or describe any insufficiencies to be remedied. If the application is contested, the time for acting is extended by 30 days.

(3) Upon receiving notice of certification of new facilities, the program administrator shall create an REC account for the designated representative of the renewable resource.

(4) The commission may make on-site visits to any certified unit of a renewable energy resource and may decertify any unit if it is not in compliance with the provisions of this subsection.

(5) A decertified renewable generator may not be awarded RECs. However, any RECs awarded by the program administrator and transferred to a competitive retailer prior to the decertification remain valid.

(o) Penalties and enforcement. If by April 1 of the year following a compliance year it is determined that a competitive retailer with an allocated REC purchase requirement has insufficient credits to satisfy its allocation, the competitive retailer shall be subject to the administrative penalty provisions of PURA §15.023 as specified in this subsection.

(1) Except as provided in paragraph (4) of this subsection, a penalty will be assessed for that portion of the deficient credits.

(2) The penalty shall be the lesser of $50 per MWh or, upon presentation of suitable evidence of market value by the competitive retailer, 200% of the average market value of credits for that compliance period.

(3) There will be no obligation on the competitive retailer to purchase RECs for deficits, whether or not the deficit was within or was not within the competitive retailer's reasonable control, except as set forth in subsection (m)(2) of this section.

(4) In the event that the commission determines that events beyond the reasonable control of a competitive retailer prevented it from meeting its REC requirement there will be no penalty assessed.

(5) A party is responsible for conducting sufficient advance planning to acquire its allotment of RECs. Failure of the spot or short-term market to supply a party with the allocated number of RECs shall not constitute an event outside the competitive retailer's reasonable control. Events or circumstances that are outside of a party's reasonable control may include weather-related damage, mechanical failure, lack of transmission capacity or availability, strikes, lockouts, actions of a governmental authority that adversely effect the generation, transmission, or distribution of renewable energy from an eligible resource under contract to a purchaser.

(p) Renewable resources eligible for sale in the Texas wholesale and retail markets. Any energy produced by a renewable resource may be bought and sold in the Texas wholesale market or to retail customers in Texas and marketed as renewable energy if it is generated from a resource that meets the definition in subsection (c)(14) of this section.

(q) Periodic review. The commission shall periodically assess the effectiveness of the energy-based credits trading program in this section to maximize the energy output from the new capacity additions and ensure that the goal for renewable energy is achieved in the most economically-efficient manner. If the energy-based trading program is not effective, performance standards will be designed to ensure that the cumulative installed renewable capacity in Texas meets the requirements of PURA §39.904.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 21, 1999.

TRD-9908924
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Effective date: January 10, 2000
Proposal publication date: October 22, 1999
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Chapter 26. SUBSTANTIVE RULES APPLICABLE TO TELECOMMUNICATIONS SERVICE PROVIDERS

Subchapter R. PROVISIONS RELATING TO MUNICIPAL REGULATION AND RIGHTS-OF-WAY MANAGEMENT

16 TAC §26.465

The Public Utility Commission of Texas (commission) adopts new §26.465 relating to Methodology for Counting Access Lines and Reporting Requirements for Certificated Telecommunications Providers with changes to the proposed text as published in the October 8, 1999 *Texas Register* (24 TexReg 8678). This section is adopted under Project Number 20935.

New §26.465 implements the provisions of House Bill 1777 (HB 1777), Act of May 25, 1999, 76th Legislature, Regular Session, chapter 840, 1999 Texas Session Law Service 3499 (Vernon) (to be codified as an amendment to Local Government Code §283.001, *et seq.*). HB 1777 requires the commission to establish a uniform method for compensating municipalities for the use of a public right-of-way by certificated telecommunications providers (CTPs). Not later than March 1, 2000, the commission must establish, for each municipality, rates per access line, by category, for the use of the rights-of-way in that municipality. The sum of the amounts derived by applying the commission's access line rates by category to the total number of access lines by category in the municipality, shall be equal to the municipality's base amount. This rule establishes the procedures for counting access lines, by category, and requirements for reporting access line counts.

Prior to publication of the proposed rule, the commission staff held a workshop on September 1, 1999 at the commission offices. Input received from the commenters was used to develop the proposed rule. A public hearing on the proposed rule was held at the commission offices on November 5, 1999. Representatives from municipalities and industry, and other affected persons, participated in the hearing and provided written comments. To the extent the oral comments differed from the submitted written comments, such comments are summarized herein.

Upon publication of the proposed rule, the commission requested specific comments regarding whether the access line counting methodology in this rule is consistent with the access line counting methodology used in the commission's USF dockets (Docket Numbers 18515, *Compliance Proceeding for Implementation of the Texas High Cost Universal Service Plan,* and 18516, *Compliance Proceeding for Implementation of the Small and Rural ILEC Service Plan*) and/or the Rate Reclassification Project (Docket Number 18509, *Application of Southwestern Bell Telephone Company to Revise General Exchange Tariff, to Change Rate Group Classification of Fifty-Two (52) Exchanges*) and, if not, whether it should be. In addition, the commission requested comments regarding the inclusion of lines that a CTP, either an incumbent local exchange carrier (ILEC) or a competitive local exchange carrier (CLEC) provides to itself, in the access line count. Further, the commission solicited comments on whether connections (transmission facilities) to wireless providers which are used solely for the purpose of providing wireless telecommunication services should have to be counted as access lines and, if not, whether an exemption creates implications for Internet service providers and other providers of voice or data transmission whose access lines are counted. Finally, the commission asked for specific comments regarding the costs associated with, and benefits that will be gained by, implementation of the proposed section. Where parties responded to the above questions, those comments have been summarized, as well.

Hearing and Commenters

The following parties filed comments on the rule language: AT&T Communications of the Southwest, Inc. (AT&T); TXU Communications Telephone Company (TXU); NorthPoint Communications (NorthPoint); Rhythms Links, Inc. (Rhythms); City of Garland and City of San Angelo (Garland/San Angelo); Texas Coalition of Cities on Franchised Utility Issues (TCCFUI), a coalition of over 100 Texas cities; Texas Municipal League (TML); GTE Southwest Incorporated (GTESW); Southwestern Bell Telephone Company (SWBT); Austin, El Paso, Everman, Irving, Laredo, Missouri City, Plano, and Rosenberg (Cities); Addison, Bedford, Colleyville, Euless, Farmers Branch, Grapevine, Hurst, Keller, Killeen, North Richland Hills, Pasadena, Texas City, Tyler, West University Place, and Wharton (Coalition) (hereinafter, Cities and Coalition will be referred to jointly as "Cities"); TEXALTEL; CLEC Coalition; City of Dallas (Dallas); and MCI WORLDCOM (MCIW).

Consistency of line counting methodology

Several commenters responded to the commission's question on whether the access line counting methodology proposed in this rule is consistent with the access line counting methodology used in the commission's Universal Service Fund (USF) dockets (Docket Numbers 18515 and 18516) and/or Rate Reclassification Project (Docket Number 18509), and, if not, whether it should be. TEXALTEL responded that HB 1777 very specifically instructs the commission as to how access lines are to be counted for municipal franchise purposes; TEXALTEL concluded that HB 1777 provides more explicit instructions than in the USF context. TEXALTEL agreed that, to the extent the commission has latitude within the language of HB 1777 to choose to conform or not conform to USF definitions, all other things being equal, consistency is desirable. Cities, joined by Dallas and TML, echoed this sentiment, stating that, to the extent these dockets deal with the same issues, there should be consistency; however, while there are overlaps between HB 1777 and the commission's other dockets (18515/18516 and 18509), there is only an imperfect correlation. TXU contended that it is not necessary for the methodologies to coincide because USF monies will be received for access lines both inside and outside a city's boundaries, while fees for right-of-way (ROW) compensation are limited to within a city's boundaries. Further, TXU pointed out that USF is received only for flat rate single-line residential lines and the first five flat rate single-line business lines at a customer's location.

Cities (endorsed by Dallas and TML), SWBT and CLEC Coalition responded that the line counting methodology under HB 1777 does not need to be consistent with either the USF dockets (Docket Numbers 18515 and 18516) or commission Docket Number 18509. SWBT pointed out that the statutory purposes and applicable definitions of "access line" vary in each of these contexts, underscoring their position that the methodologies should not be consistent. CLEC Coalition reiterated this point, arguing that the methodologies were specific to the purposes of each docket and a separate counting methodology must be established to implement HB 1777.

The commission agrees that, where feasible, consistency is a desired outcome. However, as noted by commenters, the commission's USF dockets and the rate reclassification project have significantly different purposes which dictate the different definitions of access lines. For instance, the USF Docket does not track access lines by municipal boundaries, and does not differentiate between categories of access lines. Accordingly, the commission will not seek to revise the proposed counting methodology under HB 1777 for purposes of matching other commission methodologies at this time. However, the commission reserves the right to revisit the issue of consistency between counting methodologies when, pursuant to HB 1777, the commission reviews the definition of "access line" in the future.

Inclusion of company lines in access line count

Several commenters responded to the commission's question regarding the inclusion in the access line count of lines that a certificated telecommunications provider (CTP), either an incumbent local exchange carrier (ILEC) or a competitive local exchange carrier (CLEC) provides to itself. TEXALTEL responded that the desire is that the assessment of fees and pass-through be simple to administer, auditable, easy to explain to customers, and not subject to challenge or contest. TEXALTEL submitted that to assess fees on non-revenue producing lines would complicate the process, arguing that, in order to recover the fees paid on such non-revenue producing lines, CTPs would have to pass through a slightly higher fee on the revenue producing lines than the fees charged by the cities. TEXALTEL argued that the commission should simply exclude such lines. TXU echoed the concern that lines used by a CTP do not produce revenue and should, therefore, be excluded from the access line count. GTESW stated that company official lines should continue to be exempt because these lines are not a source of revenue and, therefore, have been exempted in the past. SWBT agreed with this position, asserting that the services it provides for its own use have never been included in any form of municipal fee assessment; SWBT further argued that HB 1777 gives no indication that the Legislature contemplated such a complete departure from historical practices. GTESW also pointed out that in the counting of lines for gas and electric utilities, company official lines are excluded.

Moreover, GTESW reasoned that these lines do not terminate at an end-use customer's premises (as that phrase is generally defined). AT&T contended that the phrase "end-use customer" historically has been defined as the ultimate, retail customer; that same historical definition is the only one that makes sense in every place the phrase is used in HB 1777. AT&T proposed that the commission should require a CTP to include in its access line count only those access lines provided to itself for its own end-use. AT&T argued that all other access lines should be excluded; AT&T maintained that excluding some facilities from consideration as access lines is consistent with the intent of HB 1777.

SWBT also argued in favor of excluding from the HB 1777 access line count lines that a CTP provides to itself. SWBT contended that such lines are outside the statutory definition of "access line," which is defined in the Local Government Code §283.002 in terms of transmission paths and termination points extending to or provided to an "end-use customer." CLEC Coalition also argued that a CTP is not an end-use customer as that term is used in the Local Government Code §283.002, maintaining that the term "end-use customer" denotes a third-party purchaser of goods or services. SWBT argued that it is not its own customer; instead, the ultimate retail consumer of SWBT's sold services is the end-use customer within the meaning of HB 1777 and pursuant to Texas case law. SWBT also contended that inclusion in the access line count of lines a CTP provides to itself would require a retroactive, manual adjustment to each customer's account at the end of the year to effectuate CTPs' right of pass-through. SWBT cited PURA §51.009, Municipal Fees, and §54.206, Recovery of Municipal Fee, as support for CTPs' right to pass through any municipal fees that are assessed on the lines they provide to themselves. SWBT asserted that inclusion of such lines would result in a time-consuming and costly manual adjustment on an annual basis. SWBT stressed that HB 1777 requires that the commission consider administrative convenience in writing its rules. SWBT also maintained that a very large number of the lines that a CTP provides to itself do not burden the public ROW because, in many cities, the buildings that house the largest number of SWBT employees (and therefore the largest number of company official lines) also house the central offices that serve those lines; Thus, the company lines do not intrude into the ROW.

On the other hand, Garland/San Angelo argued that there is no reason under the Local Government Code, Chapter 283, to exclude from an access line count those lines that an ILEC or CLEC provides to itself. Garland/San Angelo argued that if the line goes through a ROW, it should be counted and that nothing in the Local Government Code, Chapter 283, provides that, in order to be counted, a fee must be received by the CTP for the access line. TCCFUI added that, for the sake of consistency, all lines should be included. Dallas endorsed these comments.

The commission agrees that HB 1777 defines access line in terms of the end-use customer; the commission has followed this approach in determining whether other types of lines ought to be included in the access line count. The commission agrees with SWBT and the CLEC Coalition that a CTP cannot be an end-use customer of itself. Therefore, consistent with the definition of access lines in the Local Government Code §283.002, and with the concept that end-use refers to *retail* end-use customers, the commission believes that it is appropriate to exclude company official lines from the access line count. The commission clarifies that this exclusion for company official lines does not apply to lines that a CTP provides to its employees, such as employee concession lines or other similar types of lines provided to employees, that may not be revenue-producing and are used for matters other than official business. Given that the employees would be the end-use customers, the commission believes that an adjustment to the accounts of other customers to effectuate CTPs' right of pass-through, as suggested by SWBT and TEXALTEL, is unwarranted. Accordingly, the commission declines at this time to require the inclusion of company official lines but does require the inclusion of employee concession lines in the access line counts. For additional discussion please refer to the commission discussion for subsection (e)(4).

Inclusion of transmission facilities to wireless providers

Multiple parties commented on the issue of whether connections (transmission facilities) to wireless providers which are used solely for the purpose of providing wireless telecommunications services must be counted as access lines and, whether an exemption for such lines would create implications for Internet service providers (ISPs) and other providers of voice or data transmission whose access lines are counted. TEXALTEL, SWBT and CLEC Coalition responded that a wireless provider is not an end user and, thus, the services fall outside the definition of "access line." GTESW argued that transmission facilities to wireless providers are just another example of interoffice trunking. SWBT made the same argument using inter-facility transport as an example that should not be counted as access lines, as such transport does not terminate at an end-use customer. GTESW argued that an access line should include each transmission path to an end-use customer, so that, in the case of a wireless or Internet provider, this should only include landlines provided to the wireless provider or Internet provider as an end-use customer. CLEC Coalition also indicated that connections to wireless providers used solely for the purpose of providing wireless telecommunications services should not be counted as access lines. GTESW emphasized that the language of HB 1777 specifically excludes wireless airwaves as being outside the ROW.

At the public hearing, SWBT explained that no sales taxes are applied to the facilities purchased by a wireless provider that is tying its cell sites together, or tying its cell site to the ILEC switch. Thus, the wireless provider is not the retail customer, but instead is part of the wholesale transaction providing the wireless service to wireless customers. Cities asserted, however, that the exemption of wireless providers from HB 1777, makes them, in that instance, a retail customer. Cities went on to add that the cell site itself is purchasing the services, making it the customer premises. El Paso argued that the entire retail/wholesale concept should not be applied to the question of how to define the end use customer for purposes of compensation for use of ROWs because they are two different things. Dallas pointed out that lines interconnecting different companies and wireless providers have historically been assessed franchise fees. SWBT and GTESW did not necessarily agree that this was the practice statewide.

TML, on the other hand, contended that HB 1777 does not exempt wireless providers when they place or maintain lines in the ROW. TML asserted that, to exclude lines used to connect "CTP, wireless provider or IXC equipment" or backhaul lines that are so located, not only creates a competitive advantage for such providers, but prevents cities from meeting their legal obligations and the intent of HB 1777. TML further asserted that a wireless provider is an "end-use customer," and such a provider's cell site is the "customer premise."

TML and Cities, joined by Dallas, asserted that to exclude cell site customers and CTP equipment would expand the meaning of "interoffice transport" under the Local Government Code, §283.002(1)(B), in a way not contemplated by the statute. Cities pointed out that, for the purpose of HB 1777, there is no distinction between a wireless provider's use of access lines in the public ROW and that of any other customer of a CTP. In contrast, AT&T asserted that lines provided to wireless providers qualify as interoffice transport. AT&T cited the Local Government Code, §283.002(1)(B), which specifically excludes "interoffice transport or other transmission media that do not terminate at an end-use customer's premises" from being considered an access line. Both AT&T and CLEC Coalition cited the Local Government Code, §283.056(f), as evidence that HB 1777 expressly contemplates transmission media that do not terminate at an end-use customer's premises, and moreover, provides that those lines are not to be used in the calculation of the compensation. Therefore, claimed AT&T, transmission facilities provided to wireless providers, who in turn use them to provide services to their end users, may not be counted as access lines. AT&T concluded that just as an ILEC or CLEC may have interoffice lines in the public ROW to connect their facilities that are excluded from counting, so would the lines used in connecting to a wireless provider's facility be similarly excluded.

Cities, as endorsed by Dallas and TML, cited the Local Government Code, §283.002(1), to show that a wireless provider is an "end-use customer" because the provider's cell site is the "customer premises." TCCFUI, supported by Dallas, echoed that the wireless carrier is the end-use customer of a service being provided over facilities located in a municipal ROW. El Paso explained that the wireless carrier is purchasing land-line telecommunications service. TEXALTEL differentiated such lines used by the telecommunications provider itself from lines used as a part of the process of providing telecommunications services. Cities, joined by Dallas and TML, maintained that, because HB 1777's purpose is to establish a competitively neutral, nondiscriminatory compensation method, to exclude one significant type of customer without a valid legal distinction is *prima facie* discriminatory and unlawful, and also not competitively neutral. Cities also addressed the issue of implications for ISPs and other providers of voice or data transmission whose access lines are counted, stating that an exclusion for wireless providers' lines would discriminate against ISPs and other providers, in that they would now have to subsidize wireless providers. CLEC Coalition, on the other hand, stated that the implications of any exemption for ISPs remains to be seen, but that there are important distinctions between an ISP and a wireless provider; an ISP provides information services, not telecommunications services, to its end-use customers.

Cities, joined by Dallas and TML, believed that the proposed rule instills confusion by purporting to exclude (or include) lines purchased by cell site customers and customers of interexchange carriers (IXCs) when, in fact, for purposes of HB 1777, these customers cannot be deemed to provide "retail services" as they are not CTPs covered by this chapter. Therefore, Cities, supported by Dallas and TML, asserted that there is no statutory or policy basis to treat cell site customers or IXC customers differently than any other retail customer. Garland/San Angelo asserted that all access lines must be counted if there is no exemption for them granted by statute and, therefore, connections to wireless providers should not be exempt from the access line count. Garland/San Angelo maintained that the statute does not authorize excluding wireless providers as customers.

TCCFUI, joined by Dallas, strongly opposed exempting those access lines used or purchased by a wireless carrier to complete calls, stating that such an exemption violates one of the stated purposes of HB 1777–to ensure there is no competitive advantage or disadvantage among providers. TCCFUI, joined by Dallas, strongly opposed the presumption that access lines to wireless providers are somehow different than lines to other customer classes, including resellers and rebundlers. TCCFUI and Dallas maintained that the connection between the cell tower and the wireline carrier's switch goes through a ROW and that any exemption denies the municipality its right to collect compensation. Further, argued TCCFUI and Dallas, it makes no difference if the end user wireless provider is a subsidiary of the original provider–CTPs should not be exempted from paying access fees simply because they resell access lines to their own subsidiaries, wireless or not. TCCFUI also raised concerns that once one exemption is created, others will seek such an exemption, too.

The commission recognizes the potential for confusion in counting only certain types of lines and excluding others. The commission notes that the confusion may be fueled by the fact that the term "interoffice transport" is not defined within the statute. Nonetheless, the commission believes that wireless lines must be excluded for the following reasons: first, the Local Government Code §283.002(6) states that, "the term (public right-of-way) does not include the airwaves above a right-of-way with regard to wireless telecommunications." By excluding the airways from the definition of the ROW, the Legislature specifically excluded the "last mile" of the wireless network from the application of HB 1777. Next, each element of the definition of "access line" refers to transmission media *within* the right-of-way extended to the *end-use customer's premises.* Since the framework of HB 1777 is built around the "last mile," (the final segment of the network which terminates at the end-use customer's premises), it would be inappropriate to call a wireless provider an end-use customer simply to capture those lines. Therefore, by definition, the wireless network falls outside the definition of access lines. Furthermore, the proposed subsection (f) of the commission's rules has held that other landline-based CTPs are not end users. To be consistent under this approach, the commission also excludes the lines terminating at a wireless provider. The commission also clarifies that it does not consider lines to wireless providers to be interoffice transport. The commission notes that the FCC is currently addressing issues related to the treatment of wireless providers vis-à-vis landline-based providers. The commission reserves the right to revisit the issue of whether wireless providers are end-use customers, should the FCC make a determination on this issue.

Costs and benefits of rule

Several commenters expressed opinions analyzing the costs and benefits of the proposed rule. GTESW highlighted consistency in the way CTPs count access lines and ease of administration for CTPs, the commission, and municipalities as benefits of the proposed rule. GTESW acknowledged that the proposed rule would increase costs for the commission and municipalities to assure no duplicate charging of access line fees occurs. AT&T expanded on the cost analysis, stating that precise cost quantification of system development, modification and deployment remains difficult, but is expected to be substantial as entirely new software and accounting systems will have to be developed. SWBT generally shared the position that there will be significant costs associated with implementation of the rule. CLEC Coalition stated that costs to CTPs will be very high. Creating a system that will not only count access lines (as they are ultimately defined), but which will also segregate access lines by category and municipality is very burdensome and costly. CLEC Coalition members intend to recoup costs from customers, so it is imperative that the counting methodology be tied to the CLEC's billing system–but it may be months before such systems are capable of reflecting these fees on customers' bills.

The commission recognizes that the changes required under HB 1777 will necessitate modifications to a CTP's billing system. However, consistent with HB 1777, the counting of access lines under this rule focuses on the end-use customer, and the counting methodology is designed to track as much as possible the CTPs' billing systems, thereby minimizing administrative costs to the extent possible.

Inclusion of Lifeline and Tel-assistance lines

Several commenters responded to questions regarding an exemption for Lifeline and Tel-assistance lines, raised during the commission workshop. GTESW did not oppose assessing fees on these lines but wanted to ensure that the rule is nondiscriminatory and competitively neutral; either include lines in all municipalities, or exclude lines in all municipalities; GTESW also felt that such a standardized approach is essential for administrative simplicity, a key objective of HB 1777. Like GTESW, SWBT stated it has no objection to exempting Lifeline and Tel-assistance lines, but asked that for purposes of administrative simplicity and nondiscrimination, such lines be treated consistently statewide–either all included or all exempt. SWBT pointed out that HB 1777 provides no explicit exemption for Lifeline and Tel-assistance lines, but in SWBT's experience, most municipalities have chosen to exempt them from municipal fees.

Dallas opposed adding another exclusion for Lifeline services, because excluding a new class of customers from the definition of access lines will automatically increase the rates of other customers. Further, Dallas argued that such an exclusion seems to establish a fourth access line category, not approved under HB 1777. Dallas also maintained that, once an exclusion is created, others, such as schools or charities, may seek similar exclusions.

The commission believes that HB 1777 does not allow the commission to specifically exclude a class of access lines. As commission rules have already established the maximum three access line categories, there is no basis for establishing Lifeline and Tel-assistance lines as a separate access line category. Furthermore, some municipalities have historically chosen to exclude Lifeline and Tel-assistance lines from franchise fee compensation, while others have chosen to include compensation from these lines. Because HB 1777 creates a statewide system of municipal compensation, the commission must either include Lifeline and Tel-assistance lines from the access line count in all municipalities or exclude Lifeline and Tel-assistance lines in all municipalities. However, the commission does not want to pre-judge a municipality's choice regarding compensation from Lifeline and Tel-assistance customers in this rule. Therefore, the commission concludes that at this time, it is appropriate to include Lifelines and Tel-assistance lines as part of the access line count, but will defer to the adoption of the rates and compensation rule, §26.467 of this title (relating to Rates, Allocation, Compensation, Adjustments and Reporting), on whether or not municipalities have the option to forgo compensation from these lines. Depending upon the determination made in §26.467, CTPs may be required to separately identify Lifeline and Tel-assistance lines on an as-needed basis. To sum up, Lifeline and Tel-assistance access lines have been added to the list of lines to be counted under subsection (e) of this section.

Section 26.465(c)(1)-transmission media

Proposed §26.465(c)(1), defines transmission media as, "The physical wires within a public-right-of-way that may consist of, but are not limited to, copper, coaxial, or optical fibers or other media, extended to the end-use customer's premises within the municipality, that allow the delivery of local exchange telephone services within a municipality, and that are provided by means of owned facilities, unbundled network elements or leased facilities or resale."

Several comments were received on proposed §26.465(c)(1). Dallas asserted that the proposed definition limits the media to "physical wires" and to those providing switched services only, and pointed out that facilities typically found in the ROW include a number of other facilities. To eliminate any possible inadvertent limitation caused by the definition, Dallas proposed a definition that includes all facilities located in a public ROW such as coaxial cable, fiber optics, poles, manholes, conduits, and "other plant equipment and appurtenances used to deliver telecommunications services to the end-use customer's premises." Dallas argued that, without such a change, the exception may be broader than the rule. Further, Dallas pointed out that such a definition would permit more technological flexibility than the use of the word "wires."

Garland/San Angelo observed that the descriptive language in the Local Government Code, §283.002(1)(A)(i) that applies to transmission "path" has been erroneously applied to transmission "media" in the proposed rule. Garland/San Angelo explained that there are different types of media and the transmission path is provided through the media. Garland/San Angelo argued that because "wires" may be too limiting, it should be replaced with "facilities." TCCFUI agreed with this recommended change. SWBT concurred with the replacement of the term "wires" with "facilities," among other wording changes.

Cities, as endorsed by Dallas and TML, found the definition of "transmission media" confusing and unnecessary. In particular, Cities pointed out that the definitional test of "physical wires within the public ROWs" would result in the exclusion of lines within any building served through a PBX (or other equipment).

The commission agrees with the commenters that the definition of transmission media may be confusing. Also, given that the categories of access lines are no longer distinguished by bit rate or speed (bandwidth), the commission believes that the definition of transmission path may be unnecessary. Therefore, the commission deletes the definition of transmission media from this section of the rule.

Section 26.465(c)(2)-transmission path

Proposed §26.465(c)(2), defines transmission path as, "A physical or virtual path within the transmission media used to provide a certain level of service. A transmission path may consist of, but is not limited to, one or more wires, either as a pair of copper wires, coaxial, optical fiber, or a combination of any of these.

(A) Each individual service, including a service offered as part of a bundled group of services, shall constitute a single transmission path. Features of services, such as call waiting and caller-ID, shall not constitute a separate transmission path.

(B) Where a service or technology is channelized, each channel shall constitute a single transmission path."

Several commenters addressed the commission's definition of "transmission path." TEXALTEL reiterated its view that each service should be counted as an access line, regardless of the number of paths within that service. TEXALTEL noted, however, that if the commission goes forward with the "channel" concept as shown in the proposed rule, the definition of transmission path should be amended (by adding the italicized section) to read: "Where a service or technology is channelized, each channel *over which service is provided* shall constitute a single transmission path." CLEC Coalition argued against counting each channel of a channelized service because doing so may result in the ROW fee exceeding the cost of the service. CACC made this same point at the public hearing, citing examples of customers paying for both a T1 line and for each channel of the T1 line, as well. CLEC Coalition contended that this result was not intended by HB 1777 and has no basis under the legislation. In addition, CLEC Coalition pointed out that channelizing does not physically modify the transmission media that occupies the ROW or place a greater burden on the ROW. GTESW agreed, stating that there is no additional incursion in the ROW for providing a multi-channel product.

Garland/San Angelo discussed the overlap between definitions in §26.465(c)(1) and (c)(2), recommending that (c)(2) be revised to remove references to media such as wires or fiber. SWBT agreed that "wires" should be replaced with "physical facilities" and also recommended that "a certain level of service" be specifically identified as "switched local exchange telephone" service. Similarly, CLEC Coalition recommended that the service level be specifically identified, but suggested the description be "retail," on the basis that level of service is no longer necessary given that access line categories are no longer distinguished by bit rate or speed. SWBT also recommended the addition of the word "cable" after "coaxial." Cities, endorsed by Dallas and TML, reiterated their concern that the wording of §26.465(c)(2), when read with the proposed (c)(1), would result in the exclusion of lines inside buildings such as multiple dwelling units, because the commission's proposed definition did not make specific references to other physical structures in such locations which might serve as a transmission media for the transmission path.

Under §26.465(c)(2)(A), CLEC Coalition recommended that if a bundled group of services is offered to an end-use customer and each "individual" service of that bundle is provided over the same transmission media, it should be counted as a single transmission path or a single access line. CLEC Coalition asserted that, as technology develops, the "bundle" of services that can be transmitted over the same transmission media is likely to increase due to technological advances at either end of the cable. CLEC Coalition contended that it is not necessary to cut a street and lay additional cable each time an additional service is provided to an end-use customer. CLEC Coalition maintained that HB 1777 says ROW compensation must be consistent with and have a nexus to the provider's incursion into the public ROW, arguing that where there is not some physical nexus or connection or burden on the ROW, there is no basis to see incremental increases in the cost. Imposing unrelated or inflated ROW costs on the deployment of advanced technology will be a disincentive to use and enjoy the benefits of advanced technology and is contrary to the federal Telecom Act and Texas law. Further, the CLEC Coalition argued that counting "individual" services and attempting to determine whether a product is a "service" or merely a "feature" of a service, is like counting wires–inconsistencies will abound and verification will be enormously burdensome and costly. CLEC Coalition concluded that unless and until the commission modifies the definition of "access line" in two years, the nature or type of service provided over an access line is not relevant to a determination of ROW compensation.

AT&T gave lengthy comments on the difficulties associated with the commission's proposed definition of "transmission path." AT&T argued that the proposed definition of "transmission path" is inconsistent with HB 1777 and departs from the underpinnings of both federal and state law. AT&T stated that the commission's proposal would impose multiple access line fees without regard to the physical facilities or ROW burden. AT&T argued that, under HB 1777, in order for a transmission path to be an access line, it must: 1) be physically in the ROW; 2) be extended to the end-use customer premises; 3) allow the delivery of local exchange services within a municipality; and 4) be provided by means of owned facilities, unbundled network elements (UNEs) or leased facilities, or resale. AT&T contended that the proposed definition fails to recognize these requirements and: 1) would allow a virtual path to be a transmission path; 2) does not require each transmission path to be extended to an end-use customer's premises; 3) fails to reflect that a transmission path must allow delivery of local exchange services–but says that a path may be "used to provide a certain level of service;" and 4) fails to reflect the means by which the path may be provided.

AT&T claimed that the proposed definition would require the counting of a single transmission path for each individual service offered, while a feature of a service would not constitute a separate path. AT&T raised concerns that there is no definition regarding what is a service and what is a feature of a service, asking whether Caller ID, per line blocking, and per call blocking are features or services.

Specifically referring to §26.465(c)(2)(B), AT&T found the commission's choice to count each channel as a single transmission path fundamentally flawed. AT&T observed that the rule is not restricted as to who does the channelizing. If, for example, the end-use customer channelizes the line, the CTP may have no information as to the number of channels that have been created and are being used. GTESW echoed this concern, stating that GTESW would not know the number of channels used by a customer or how the facility is being multiplexed. GTESW emphasized that this would be particularly difficult on facilities provided to other CTPs. AT&T added that the commission's proposal would allow higher fees on a technology that imposes less burden on the ROW and will result in a disincentive to the development and purchase of new technology. AT&T declared that the counting methodology should reward, not penalize, carriers which do more with less. AT&T also pointed out that any level of service provided over fiber optic cable is a function of the equipment placed at both ends that, again, does not impact the ROW. AT&T argued that all services should be subject to the same access line fee. One fiber facility, regardless of the equipment placed on it, should be counted as one access line, asserted AT&T.

GTESW focused on the specific billing problems associated with counting each channel, pointing out that it bills the end-use customer based upon the transmission path of the facility, not the individual channel. GTESW also stated that it cannot determine the number of channels actually being used by a customer and so cannot bill per channel without making costly changes to GTESW's ordering and billing processes and systems. Because two pairs of copper cables can be engineered to provide 24 channelized voice grade circuits, GTESW contended that it should only be subject to ROW fees for one access line and not the potential 24 channels available to the end user. GTESW emphasized that this problem becomes more complex when one considers the immense circuit-carrying capabilities of fiber optic systems.

On the other hand, at the public hearing SWBT responded that if a fee is not assessed based upon the service that is provided over that switched network that the customer orders, but is instead assessed only upon the facility that is in the ROW, SWBT would be placed at a competitive disadvantage because of the fact that SWBT serves some of its customers with the old technology of copper wires. In other words, SWBT might need 23 facilities, 23 separate copper pair wires, to provide a specific service; if the fee is assessed upon a facility basis, SWBT is assessed 23 fees, while a competitor using a T1 line to provide the same service would be assessed only one fee. SWBT urged the commission to take into consideration issues of competitive neutrality. Dallas echoed the need for fees to be assessed the same way, regardless of whether the service is provided over twisted-pair copper wires or a channelized fiber optic line. TEXALTEL's position was that the access lines be counted based on services, but the provider should define what the service is; a large ISDN sold as one service should be defined as one access line, or 150 local exchange lines sold separately should be counted as 150 access lines.

On the other hand, TML and Cities explained that cities do not share industry's traditional position that the issue is a burden on the ROW, a cost argument. Instead, TML and Cities asserted that ROW compensation is based upon the value of the use of the ROW and, therefore, the greater the profit from the commercial enterprise that is using the ROW, the greater the value of the use of the ROW. TML also pointed out that HB 1777 was a compromise between cities and industry whereby the parties did not have to decide that ultimate issue and instead ensured that cities would get the customary reasonable compensation they had received in the past, generally based in some way upon gross receipts. Cities and City of El Paso argued that the federal standard of "fair and reasonable" supports the position that compensation is based on the value of the ROW, not the burden on it. Cities stated that this issue has not been totally resolved either way. City of El Paso asserted that the issue of physical occupation of the ROW is only a threshold question in a two-tier process; once the presence of facilities in the ROW has been established, the calculation of municipal compensation occurs based upon the number of access lines, as defined in the statute.

At the public hearing, SWBT asserted that, on switched lines, the CLEC or the ILEC will always know how many services have been provided to a customer over that line, whether the services were packet switched or simply analog service. TEXALTEL agreed that the providers know how many paths the customer will be allowed to use simultaneously to complete local calls. But both TEXALTEL and AT&T pointed out that the provider would not necessarily know how many numbers the customer actually has in use on their side of the facilities, although the provider would probably know the amount of toll numbers that are in use by the customer due to the need to program the switch to complete the calls to those numbers.

SWBT cautioned that while one may know the number of paths for switched services, the same is not true for point-to-point connections that do not tie to the public switched network. SWBT argued that expanding the channelization concept of payment to the private line or point-to-point connection is untenable from the ILEC or CLEC's point of view because they do not know what the customer is using the private line for. CLEC Coalition expressed concern over apparent inconsistent treatment where lines channelized by the CTP would be counted, while lines channelized by the end-use customer would not be counted. Dallas, on the other hand, observed at the public hearing that the customer's actions cannot be controlled, but the CTP's billing records can be recognized and treated accordingly.

The commission has amended the definition of transmission path to exclude references to "wires" and, therefore, does not find it necessary to adopt the clarification suggested by Garland/San Angelo and SWBT. The commission agrees with TEXALTEL's definition for channelization and has included language similar to that proposed by TEXALTEL in revised subsection (c)(2)(E). The commission believes that the concerns raised by Cities, Dallas, and TML regarding the exclusion of lines within building facilities is unfounded because the definition of access line in the Local Government Code §283.002(1)(A)(i) includes all access lines "extended to the end-use customer's premises." Therefore, to the extent an access line extends to an end-use customer residing in a multiple dwelling unit, that access line will be counted.

The commission rejects CLEC Coalition's and AT&T's comments with regard to channelizing and equating transmission paths with services for the following reasons. As set forth in the Local Government Code §283.001(c)(1), administrative simplicity is a guiding principle of HB 1777; throughout this process, industry has repeatedly highlighted the need for ease of administration. Next, the commission believes that, as a practical matter, performing an actual count of the physical infrastructure buried in the rights-of-way of every city in the state of Texas would be impossible. Furthermore, during this rulemaking project, most of the telecommunications providers requested that the commission utilize existing billing systems to develop an access line count. Taking these factors into consideration, the commission has proposed a method to count facilities in the right-of-way through the services provided over the facilities, instead of burdening the providers with performing an actual count of the physical infrastructure in the rights-of-way. Under the commission's proposed rules, services and channelization serve as a *proxy* for the actual facilities in the right of way. Using this method, as requested by several industry participants, companies need only their billing records to develop an access line count. Finally, should the commission follow AT&T's and CLEC Coalition's proposal for counting access lines, it creates the potential for discriminatory treatment of end-use customers and is inconsistent with the statute. The definition of access line in the Local Government Code §283.002(1)(A)(i) equates each "access line" with "*each* switched path" (emphasis added). It is the commission's interpretation that, even if several switched services can be bundled together and offered over a single strand of fiber optic cable, at the central office end they have to be demultiplexed into individual switched paths, either externally or as an integral function of the switch. Since this results in *multiple switched paths*, each switched service in a bundled group of services should be counted as a single transmission path. The commission believes that the proposed definition will result in a consistent count of access lines, will be easily auditable, and will be administratively simple. The commission has added language to revised subsection (c)(2)(A), (B), and (C) and to subsection (d) to provide clarity and to help identify the types of services that should be counted. Please also refer to commission's response for subsection (d)(1)(C) for further discussion on counting access lines. It should be noted that the commission's counting has tied switched transmission path to circuit-switched networks, as this is how local exchange services are currently provided. In the future, if it is determined that services provided over other switched networks, such as packet switched networks, are local exchange services, the commission reserves the right to address this issue appropriately at that time.

The commission, however, agrees with AT&T's concern that the term "services" is not defined and that it could be misunderstood and confused with the term "features," thereby resulting in an inaccurate access line count. The commission will address this by providing detailed instructions in the forms used for access line data collection. The commission also notes that features do not increase the number of circuit switches and therefore, should not be counted as individual switched paths. The commission has added language to revised subsection (c)(2)(D) to clarify the types of features (or vertical services) that do not count as separate transmission paths.

The commission understands GTESW's concern regarding billing problems associated with channelization. The commission believes that CTPs have the capability to determine how many channels are provided to a customer as these are tracked by billing systems. However, if a line or circuit is channelized at the customer's end, then the CTP would have no knowledge about channelization and the commission rules for channelization would not apply. The commission also clarifies that it is not the potential number of channels that have to be counted but only the actual number of channels provided by the CTP. For instance, if a customer orders a channelized T1 line consisting only of 12 channels, then the municipal fee would be applicable only for the 12 channels ordered, not for the potential 24. The commission agrees with GTESW that two copper wires may be engineered to provide 24 channels, but notes that in other circumstances 24 copper wires may be used to provide 24 channels. The only way to ensure consistency in municipal fees between these two scenarios is to use the concept of channelization. Channelization results in multiple switched paths; the commission concludes that each switched path is an access line by definition, and therefore each channel shall be counted as an access line. The commission has added language to revised subsection (c)(2)(E) clarifying that channelization would only apply to the actual number of channels provided and only when channelized by the CTP.

Section 26.465(c)(3)-wireless provider

Proposed §26.465(c)(3) defines a wireless provider as, "A provider of wireless telecommunication services."

AT&T proposed a revision to the definition of "wireless provider." Specifically, AT&T recommended that the definition be modified to follow the language of PURA §51.002(10)(A)(iv). AT&T also reiterated that should the commission agree with AT&T that lines to a wireless provider should be excluded from the access line count, no revision to the definition would be necessary.

The commission agrees with AT&T and modifies the definition of wireless provider to reflect the language of PURA §51.002(10)(A)(iv). The commission has already responded to AT&T's concerns regarding the inclusion of lines provided to a wireless carrier in the discussion regarding end-use customer.

Section 26.465(d)(1)-Switched transmission paths

The proposed §26.465(d)(1) delineates the methodology for counting access lines for switched transmission paths. SWBT recommended revising the title to "switched services", rather than "switched transmission paths", to parallel the title of §26.465(d)(2).

The commission agrees that SWBT's suggestion provides a better catchline to subsection (d)(1) and therefore adds SWBT's suggested catchline to the original catchline.

Section 26.465(d)(1)(A)

The proposed §26.465(d)(1)(A) requires that a CTP shall determine the total number of switched transmission paths and should take into account the number of services provided and the number of channels used where a service or technology is channelized.

AT&T reiterated its comments regarding the definition of transmission path in §26.465(c)(2). AT&T supported the elimination of the proposed counting methodology which requires CTPs to take into consideration the number of services provided and the number of channels used where a service or technology is channelized. CLEC Coalition proposed deleting all references to the number of services or channels provided, reiterating its comments on channelization set forth in its response to §26.465(c)(2) above.

The commission has addressed in detail AT&T's and the CLEC Coalition's concerns regarding counting services and channelization (refer to commission's response to §26.465(c)(2)). As noted above, the commission believes that services are the best *proxy* for counting facilities in the rights-of-way. Therefore the commission retains subsection (d)(1) with minor clarifying modifications.

Section 26.465(d)(1)(B)

Proposed §26.465(d)(1)(B) stated that the bandwidth of each transmission path determines the access line category, as established in §26.461 of this title (relating to Access Line Categories).

TXU, GTESW, Rhythms, NorthPoint and Garland/San Angelo recommended that the commission remove all references to bandwidth in §26.465(d)(1)(B). Garland/San Angelo provided language revising this definition to refer to the categories established in §26.461 of this title. AT&T, CLEC Coalition and SWBT requested rejection of §26.465(d)(1)(B) as moot, in light of the commission's adoption of the access line categories. MCIW likewise observed that the commission's access line categories had been changed in the adopted version and recommended deleting references to bandwidth.

The commission agrees that the revised access line categories no longer distinguish between bandwidth, rendering

§26.465(d)(1)(B) moot. Accordingly, the commission deletes any references to bandwidth in this section.

Section 26.465(d)(1)(C)

Proposed §26.465(d)(1)(C) requires that a switched service be counted consistently in the same manner regardless of the type of transmission media used to provide that service.

AT&T reiterated its comments regarding the definition of transmission path in §26.465(c)(2) as support for eliminating this proposed requirement. AT&T pointed out that different counts that take into account differences in transmission media are appropriate since such an approach would reflect the fact that different transmission media place different burdens on the ROW. SWBT proposed some minor wording changes, including referring to *all* switched *services*, deleting the term "consistently," and changing "that" to "the".

The commission understands AT&T's response to this subsection and several other subsections is based on the argument that advanced transmission media like fiber optic cable place considerably less burden on the right-of-way than the older copper network. The CLEC Coalition has espoused a similar view. But taking transmission media into account when counting access lines raises unresolvable issues such as how to measure the burden placed by different transmission media, what unit of measurement to use, how to compare the relative burden placed by a thicker fiber optic cable versus a thinner twisted copper pair, or how to establish the relative burden placed by different lengths of cable. Furthermore, the *same* transmission media could place different burdens on the right-of-way depending upon the geography and terrain of the right-of-way. A counting methodology that required a site-by-site analysis would not meet the statute's overriding goal of establishing a uniform methodology for compensation, as access lines (as related to transmission path in the case of switched services) are the basic unit upon which any fee is assessed. Moreover, given CTPs' statements that the industry itself does not have an accurate count of the transmission media currently buried in rights-of-way, such an approach would appear to be a futile exercise.

The bill does not require such an approach to counting of access lines. The bill defines the unit of measurement as "each switched transmission path" or "each termination point or points of a nonswitched telephone or other circuit." Because this definition does not distinguish between different types of media, different sizes of cable, different lengths of cable or different terrain, examining these issues is of limited utility. The purpose of the Local Government Code, Chapter 283, is to establish a uniform method for compensating municipalities for the use of a public right-of-way that is administratively simple for the municipalities and the CTPs, competitively neutral, and nondiscriminatory. Basing the fee-per-line upon length, type, location, or size of the access line would directly contravene these principles. Moreover, such an approach could discourage competition, increase barriers to entry and create competitive advantages or disadvantages for CTPs.

Accordingly, the commission concludes that the methodology proposed by commenters is not consistent with the requirements of the Local Government Code, Chapter 283. The commission, however, agrees with the minor wording changes recommended by SWBT and has modified subsection (d)(1)(C) accordingly.

Section 26.465(d)(1)(E)

Proposed §26.465(d)(1)(E) stated that, "Where xDSL service is provided along with basic local exchange service or ISDN service, the CTP shall not count the basic local exchange service or the ISDN service as a separate transmission path and the bandwidth of the xDSL service shall determine the access line category for that service, as established in §26.461 of this title."

TXU, GTESW, CLEC Coalition, SWBT, Rhythms and NorthPoint recommended that the commission remove all references to bandwidth. MCIW likewise observed that the commission's access line categories have been changed in the adopted version and recommended deleting references to bandwidth. Rhythms and NorthPoint specifically requested that the commission modify its unique treatment of xDSL service in a line-sharing situation. Rhythms and NorthPoint suggested that when a single carrier offers different services over the same loop, only one service should be counted for taxation purposes, but when two or more carriers share the same loop, one service (e.g., xDSL) should not be singled out for assessment of franchise fees while other services are exempt. Rhythms and NorthPoint stated that doing so would unlawfully discriminate, does not further the public policy objective of protecting "plain old telephone service" (POTS) from taxation, and creates an economic disincentive for the deployment of xDSL to residences. Rhythms and NorthPoint maintained that all carriers sharing the loop should contribute a proportionate share of the franchise fees. NorthPoint added that in a two-carrier line shared environment, the DSL carrier is unfairly singled out. This shift of the financial burden does not result in additional benefit to the municipalities or end users, but places a serious burden on new entrant DSL providers. NorthPoint raised concerns that such a shift will threaten the development of line sharing, and recommended that those carriers offering the more basic local exchange service should bear the burden of reporting.

AT&T reiterated its comments regarding the definition of transmission path in §26.465(c)(2) as support for eliminating the requirement to take into consideration the number of services provided and the number of channels used where a service or technology is channelized.

SWBT, at the public hearing, maintained that DSL is a vertical service, not an access line and not subject to the fee. SWBT pointed out that using local exchange services is a good measure when talking about switched services, but the process becomes much more difficult when measuring private lines; a provider can only report what it knows, what the customer ordered, not how the customer uses that access line.

The commission accepts the recommendation from various commenters to remove the reference to bandwidth in §26.465(d)(1)(E).

The commission revises its original position and modifies the rule language to exclude all xDSL lines from the access line count for the following reasons. The definition of access line in the Local Government Code, §283.002(1)(A)(i), refers to a *switched transmission path* that *allows* the delivery of *local exchange telephone services.* It is not clear at this point if an xDSL service is a switched service or an unswitched service. An xDSL service may not be a switched service because the POTS line over which it is provisioned terminates at a circuit-switch, thereby resulting in a *switched transmission path,* but the xDSL service *does not* terminate the same way. Whether provisioned stand-alone or along with a POTS service, the DSL line in the central office connects to the ISP network and bypasses the circuit-switch. Since the commission's revised set of rules has focused on services that result in *switched paths*, DSL services cannot be counted as switched services. Further, PURA excludes "non-voice data transmission services" from the definition of local exchange telephone service (PURA §51.002 (5)(H)). Arguably, xDSL services could be considered as non-voice data transmission services, and therefore merit exclusion from the access line count under the Local Government Code §283.002(1)(A)(i). The only other option to capture an xDSL service would be to count a stand-alone DSL line as a point-to-point access line under the second part of the definition of access lines (Local Government Code §283.002(1)(A)(ii)). However, xDSL service provisioned over a POTS line would still be exempt, as POTS lines are inherently different from point-to-point lines. At this point, there is not enough evidence from the field to determine whether the xDSL technology is used for the purpose of providing point-to-point access. However, when xDSL technology is used for this purpose, those lines shall be counted consistent with subsections (d), (e), (f), of this section. Therefore, the commission refrains from making a premature determination on whether to include DSL lines in the access line count. The commission reserves the right to revisit this issue in the future. Proposed subsection (d)(1)(E) has been deleted to exclude xDSL services from the access line count.

Rhythms and NorthPoint also raised an interesting issue regarding line sharing specifically with regard to xDSL services. Since xDSL services have been exempted from the access line count pursuant to the revised definition of transmission path, the issues raised by Rhythms and NorthPoint are moot. At present, the commission's rules do not address the general issue of counting access lines in a line-sharing situation. This should not be an issue as this concept is evolving and the commission finds that there are not enough line-shared lines to warrant taking up this issue at this time. Moreover, the FCC is also in the process of dealing with this issue. The commission will revisit the issue of line-sharing at an appropriate time. The commission deletes §26.465(d)(1)(E) in its entirety.

Section 26.465(d)(2)(A)

Proposed §26.465(d)(2)(A) stated that each circuit used to provide nonswitched telecommunications services or private lines shall be considered to have two termination points, one on each end.

SWBT recommended that the commission amend subsection (d)(2)(A) to add a reference to "end-use customer", and to add language replacing "end" with "customer location identified by the customer and served by the circuit."

The commission agrees that SWBT's proposal would add clarity and makes revisions to subsection (d)(2)(A) accordingly.

Section 26.465(d)(2)(B)

Proposed §26.465(d)(2)(B) requires that a CTP shall count nonswitched telecommunications services or private lines by totaling the number of terminating points within a municipality and dividing the sum by two. Further, if the division results in a fraction, the number shall be rounded up to the nearest whole number.

TML and Cities, joined by Dallas, and AT&T opposed the counting of non-switched or private lines by totaling the number of terminating points within a municipality and then dividing by two. TML contended that because the definition of "access line" in the Local Government Code §283.002(l)(ii) explicitly provides that "each termination point or points" represents an "access line," it can not be construed to mean "one-half." TML asserted that, in other words, the plain meaning of the statute should be given effect rather than directing that the number of termination points be divided by two. Cities, as endorsed by Dallas, argued that the commission has no authority to divide the number of termination points by two, as the statute refers to "each" termination point or points.

AT&T concurred with this interpretation, pointing out that the rounding aspect of the proposal does not comply with the Local Government Code, §283.002(a)(B), which says that the access line count for nonswitched services represents a unit of measurement for each termination point or points of the phone or other circuit within a municipality. AT&T added that the commission's approach could have the unintended consequence of penalizing a customer who has termination points in different municipalities. SWBT proposed deleting subsection (d)(2)(B) altogether, asserting that the proposed requirement to divide the number of termination points in half directly contradicts the statutory definition of "access line." SWBT pointed out that the Local Government Code, §283.002(1)(A)(ii), defines each "access line" in part as "each termination point of...a non-switched...circuit," and thus, the transmission path of a switched line must be counted as one access line, but each termination point of a nonswitched circuit must be counted as one access line.

TML added that if literal application of the statutory language does, in fact, prove unfair, unreasonable, discriminatory, or otherwise unsatisfactory, then the legislature, not the commission, should amend the definition of access line in HB 1777.

The commission agrees with the various commenters that the wording of "access line" in the Local Government Code §283.002(l)(ii) explicitly provides that "each termination point or points" represents an "access line." This means that, for the purposes of counting, each point could be an access line. Accordingly, the commission has revised §26.465(d)(2)(B) to remove references to dividing the number of termination points.

Section 26.465(d)(2)(C)

Proposed §26.465(d)(2)(C) stated that the bandwidth between the two terminating points of the circuit shall determine the access line category for that service, as established in §26.461 of this title.

TXU, GTESW, SWBT, Rhythms, NorthPoint and Garland/San Angelo recommended that the commission remove all references to bandwidth. Garland/San Angelo provided language revising this definition to refer to the categories established in §26.461 of this title. AT&T requested rejection of this proposed rule as moot, given the commission's adoption of the access line categories.

The commission concurs and removes all references to bandwidth, as the revised set of categories make references to bandwidth moot.

Section 26.465(d)(2)(D)

Proposed §26.465(d)(2)(D) required CTPs to count non-switched telecommunications services consistently regardless of the type of transmission media used to provide that service.

AT&T requested that the commission reject this proposed section, reiterating its position that different counts that take into account differences in transmission media is appropriate since this reflects the fact that different transmission media place different burdens on the ROW. SWBT recommended that some minor clarifying language be added to this section to ensure consistency with other rules.

The commission declines to delete this section, for reasons outlined in the commission response to subsection (c)(2) and proposed subsection (d)(1)(C). In response to SWBT's comments, the commission makes minor changes to clarify this subsection for purposes of consistency.

Section 26.465(d)(2)(E)

Proposed §26.465(d)(2)(E) required a CTP to attribute the terminating point of a private line to the municipality where that point is located.

SWBT recommended substantial revisions to this section to ensure consistency with the Local Government Code, Chapter 283. Currently, SWBT's billing systems for the assessment of municipal fees on point-to-point services are set up to be consistent with the assessment of state and local sales taxes. Sales taxes are due in the municipality where the premises designated by the customer as its "service address" are located. SWBT argued that providers cannot readily revamp their billing systems to permit billing sales taxes on one basis and municipal fees on another. SWBT asserted that if this different approach is required, providers cannot meet the HB 1777 deadlines. Also, SWBT maintained that counting and attributing each termination point to the municipality where that particular point is located will result in tremendous implementation costs without offsetting benefits. Similarly, CLEC Coalition suggested that when the transmission path crosses more than one municipality, both points of the private line should be considered to be located in the municipality where the line originates. CLEC Coalition explained that this approach will make it easier to administer and verify the counting–more so than using fractions, rounding, and payments to two cities.

The commission recognizes SWBT's and CLEC Coalition's comments on counting point to point lines. The commission believes that subsection (d)(2)(B), as worded, would be the most equitable method of compensating a municipality for the use of its right-of-way. The municipality where a point-to-point line terminates is the one that should receive the benefit due from the CTP's use of its rights-of-way. Nonetheless, the commission recognizes the inherent difficulty in immediately revamping a CTP's billing systems to accommodate the proposed method. While the commission has retained its initial counting approach in subsection (d)(2)(B), the use of this method is optional if a CTP is unable to attribute the point to a municipality where that point is physically located. The commission has added additional language to allow some flexibility in counting point-to-point lines. The commission encourages providers to track point-to-point access lines so that a point can be attributed to the municipality where it is physically located. As suggested by the CLEC Coalition, the commission has deleted language on fractional line count adjustments in order to keep the rule administratively simple. Subsection (d)(2)(E) has been revised to allow CTPs to attribute point to point lines to the municipality identified by their billing systems if they are not able to identify the physical location of the point to point line.

Section 26.465(d)(3)

Proposed §26.465(d)(3) required the CTPs to count one access line for every ten stations served by a central office based PBX. Should the division result in a fraction of 0.5 or greater, CTPs were required to round up the access line count to the nearest whole number.

GTESW urged the commission to assess the right-of-way fee for central office based PBX-type services at 10% of the Category 2 (business) rate and require that the fee be remitted to the municipality in that same manner, instead of using a mathematical formula to determine the number of lines. Similarly, SWBT proposed that CTPs be given the option of counting each station as one-tenth of an access line, arguing that the numerical result should be the same as under the commission's proposal, but the alternative method would be more compatible with SWBT's, and perhaps other CTPs', billing systems. GTESW raised concerns that use of the formula could result in unequal and discriminatory fees on some customers.

At the public hearing, GTESW explained that they do know the number of stations in the customer's premises and that their approach is to set up the rate for each of those stations at one-tenth of the business rate. GTESW further commented that the billing system can produce access counts and, therefore station counts, but cannot fractionalize each account. SWBT echoed this concern, indicating that such an approach would require looking at each customer on a customer-by-customer basis, determining how many stations that customer has, and assessing the fee accordingly. An added difficulty is how to address rounding of the fractions. Assessing the fee at one-tenth would avoid the rounding difficulties and the customer-by-customer analysis. SWBT also mentioned that they would count only the number of stations that the customer has ordered, not the ports or the trunks. Cities had no difficulty with this approach, although Dallas requested that when lines subject to a one-tenth fee are reported, they should be differentiated from regular access lines, to assist cities in reconciling the fees.

Time Warner Telecom raised an issue at the public hearing questioning the assumption that every customer has ten stations behind that one line in a PBX-based central office service, and suggested this as an added reason not to channelize facilities that are delivered via one single demarcation point to a customer's premises.

The commission agrees that, as proposed by GTESW and SWBT, ROW fees for PBX-services could be assessed at 10% of the fee for Category 2 non-residential lines. The commission will add appropriate language in the rates and compensation rule, §26.467, to address this issue. The commission also removes the reference to the fractional adjustment in subsection (d)(3) for administrative simplicity. While CTPs may charge one-tenth of the Category 2 rate for PBX lines, CTPs must still count and report to the commission one access line for every ten stations served. If the number of central office-based PBX access lines in a municipality is proportionally large compared to the number of Category 2 lines in that municipality, an access line count that does not divide the PBX lines count by ten would result in a diluted rate for Category 2. Depending upon the number of central office-based PBX exchanges in that municipality, the diluted rates may impact compensation from Category 2 lines. Therefore, the commission declines to make any further revisions to subsection (d)(3).

Section 26.465(e)(1)

Proposed §26.465(e)(1) required CTPs to count all access lines provided as a retail service to customers.

AT&T maintained that if the commission adopts AT&T's recommendation to adopt a definition for "end-use customer" (instead of "customer"), then (e)(1) will need to be revised to read "(1) all lines provided to end-use customers." CLEC Coalition recommended this same language.

The commission agrees with commenters and adds the words "end-use" before customer in this subsection for purposes of clarification. The commission has also added a definition of customer in subsection (c)(1).

Section 26.465(e)(2)

Proposed §26.465(e)(2) required CTPs to count all lines provided as a retail service to other CTPs and resellers for their own end-use.

GTESW asserted that the access lines it provides to other CTPs and resellers should be excluded from the access line counts that GTESW reports to the commission. If the underlying CTP and the other CTP or reseller both report these lines, then the commission and municipalities will have to reconcile each count to ensure that there is no duplication of fees on a single access line. GTESW argued that it would be an unreasonable administrative burden to require the underlying provider (the line wholesaler) to perform any manner of access line reconciliation. Also, GTESW raised concerns that the availability of information on small CTPs may create problems with the commission and municipalities in reconciling access lines. AT&T proposed that if the commission adopts a definition of "end-use customer," this subsection should be deleted as unnecessary.

The commission disagrees with GTESW's interpretation of subsection (e)(2). The commission's rules require all CTPs to report their retail end user lines, and exclude lines resold to other CTPs. Therefore, to the extent that a CTP provides retail access lines to another CTP, the underlying carrier (wholesaler) is the one responsible for reporting those lines. As noted above, the commission has added a definition of customer in subsection (c)(1) but believes that retaining the language in (e)(2), with minor modifications for consistency, provides the necessary clarity.

Section 26.465(e)(3)

In §26.465(e)(3), the commission proposed that CTPs count all lines provided as a retail service to wireless telecommunication providers and interexchange carriers (IXCs) for their own end-use.

GTESW concurred with subsection (e)(3) as proposed that all "land-lines" provided to wireless providers and IXCs as a retail service for their own end-use on their premises should be counted as access lines. AT&T proposed that, if the commission adopts a definition of "end-use customer," this subsection should be deleted as unnecessary.

The commission has added a definition for "customer," but believes that retaining (e)(3), with minor modifications, for consistency, provides the necessary clarity and therefore declines to delete it.

Section 26.465(e)(4)

In §26.465(e)(4) the commission proposed that CTPs count all lines a CTP provides to itself for its own use, including a CTP's official and employee concession lines.

SWBT maintained that company official lines should not be included in the access line count. While employee concession lines are lines extending to an end-use customer's premises (they just may be "franked," or free of charge), and historically have been counted, company official lines are not extended to an end-use customer and historically have not been counted. SWBT also proposed inserting the word "access" in front of the word "line" throughout subsection (e). AT&T proposed that, if the commission adopts a definition of "end-use customer," this subsection should be deleted as unnecessary. CLEC Coalition echoed this position. GTESW reiterated its comments in response to the staff's question about "company official" lines, explaining that company official lines are not a source of revenue for the company and have historically been exempted from the calculation of ROW use payments to cities, just as gas and electric utilities do not pay cities for the utilities' own usage.

The commission has revised its position on company official lines, determining that a CTP cannot be an end-use customer of itself. However, the commission retains the language relating to employee concession lines, as these lines *are* access lines extended to an end-use customer. Subsection (e)(4) has been revised accordingly. The commission has previously addressed this issue in this adoption preamble in its response to certain questions set out in the proposal preamble. The commission also agrees with SWBT's recommendation that the term "access" be added before the term "line" and has made appropriate changes to the rule.

Section 26.465(e)(5)

In §26.465(e)(5) the commission proposed that CTPs count all lines provided as a retail service to a CTP's wireless and IXC affiliates for their own end-use, and all lines provided as a retail service to any other affiliate for their own end-use.

AT&T proposed that, if the commission adopts a definition of "end-use customer," this subsection should be deleted as unnecessary.

The commission believes that retaining subsection (e)(5), with minor modifications for consistency, provides the necessary clarity, and therefore, declines to delete it.

Section 26.465(e)(6)

In §26.465(e)(6), the commission proposed that CTPs count dark fiber to the extent it is provided as a service or is resold.

SWBT suggested that the commission revise this subsection to assess the Category 3 private line termination point fees for services provided by dark fiber. Because dark fiber can be "lit" by a non-CTP that is outside the commission's jurisdiction and not required to report access lines, assessing the Category 3 fee will diminish incursions upon competitive neutrality. GTESW contended that dark fiber should not be counted as an access line since there are no end users associated with it and, thus, it does not fit into the definition of an access line. AT&T requested rejection of this subsection, maintaining that dark fiber does not fit within the definition of "access line." AT&T argued that, while dark fiber is an unbundled network element (UNE) and a component of creating access lines, its mere existence or lease does not mean that there are customers receiving services from it.

CLEC Coalition also raised concerns about leasing capacity from a non-CTP dark fiber provider, in a situation where the dark fiber provider may already be paying municipal compensation.

CLEC Coalition requested that the rules make clear that there will not always be payment made on 100% of the reported access lines, if one reads the bill to require every line to be counted.

The commission finds merit in some of the proposals offered by commenters. The commission agrees with AT&T, in part, that dark fiber, by itself, is not an access line and should not be counted so long as it resides with the provider. Also, as pointed out by the CLEC Coalition, dark fiber provided by non-CTPs should not be counted, as HB 1777 does not apply to non-CTPs. The commission agrees with the CLEC Coalition that under certain circumstances there will not be 100% compensation from all access lines used by CTPs. On the other hand, when dark fiber is sold or resold to a customer by a CTP, who then "lights" the fiber, it becomes an access line. The challenge is that the underlying CTP may not know the access line category of the resold dark fiber. As suggested by SWBT, dark fiber should default to a Category 3 line, as this would be the most reasonable interpretation of its use. The commission has deleted subsection (e)(6), as this issue is resolved in revised (d)(2)(F).

Section 26.465(e)(7)

In §26.465(e)(7) the commission proposed that CTPs count all other lines meeting the definition of access line as set forth in §26.461 of this title.

CLEC Coalition recommended that this section be deleted.

The commission believes that the language is a catchall phrase to include all lines not currently addressed in commission rules and hence retains it.

Section 26.465(f)(1)

Proposed §26.465(f) delineates the types of lines not to be counted. Proposed subsection (f)(1) required CTPs to exclude from the access line count all lines that do not terminate at a customer's premises.

SWBT, CLEC Coalition and AT&T proposed adding the words "end-use" before the word "customer" for clarity and consistency with statutory definitions.

The commission agrees with this clarifying wording and has revised the section accordingly.

Section 26.465(f)(2)

Proposed subsection (f)(2) required CTPs to exclude from the access line count, lines used by a CTP, wireless provider, or IXC for interoffice transport, or transmission facilities used to connect such providers' telecommunications equipment for the purpose of providing telecommunications services.

SWBT proposed adding the words "to end-use customers" for clarity and consistency with statutory definitions. Cities, endorsed by Dallas and TCCFUI, raised concerns that the proposed rule could be read to exclude broad categories of access lines. In particular, Cities cited the facility connecting the PBX that is excluded because it is a facility used to connect such provider's equipment. AT&T recommended consolidating (f)(2)-(4) into one section, with minor revisions.

The commission agrees with the clarifying wording proposed by SWBT and has revised the section accordingly. The commission agrees with Cities, Dallas, and TCCFUI that broad interpretations could be made with the proposed language that may result in exclusion of broad categories of access lines. The commission's intention was to exclude back-haul facilities, as these would constitute interoffice transport. Therefore, the commission has revised subsection (f)(2) by replacing the term "transmission facilities" with the term "back-haul" facilities to provide clarity.

Section 26.465(f)(3)

Proposed subsection (f)(3) required CTPs to exclude from the access line count, lines used by a CTP's wireless and IXC affiliates for interoffice transport, or transmission facilities used to connect such affiliates' telecommunications equipment for the purpose of providing telecommunications services.

SWBT proposed adding the words "to end-use customers" for clarity and consistency with statutory definitions.

The commission agrees with the clarifying wording suggested by SWBT and has revised the subsection accordingly. The commission has also revised subsection (f)(3) by replacing the term "transmission facilities" with the term "back-haul" facilities to be consistent with the use of the term in subsection (f)(2).

Section 26.465(f)(4)

AT&T recommended consolidating (f)(2)-(4) into one section, with minor revisions.

The commission believes that consolidating (f)(2)-(4) may not provide clarity and has retained them with revisions, as outlined above.

Section 26.465(f)(5)

Proposed subsection (f)(5) required CTPs to exclude from the access line count, any other lines that do not meet the definition of access line as set forth in §26.461 of this title.

CLEC Coalition recommended deleting this subsection.

The language in (f)(5) is a catchall phrase to exclude all lines that are not explicitly identified in the commission's rules. Therefore, the commission retains (f)(5) without change.

Section 26.465(g)

Proposed §26.465(g) outlined the initial and the subsequent reporting requirements for CTPs.

CLEC Coalition raised a number of questions about the reporting of access lines that are resold, leased, or otherwise provided to another CTP. First, CLEC Coalition asked whether a CTP reselling lines or leasing capacity must assume that the transmission media is physically located within a public ROW. Second, CLEC Coalition questioned whether capacity or facilities leased from a non-CTP must be reported but with an indication that no fee will be remitted in connection with such access lines. In particular, CLEC Coalition requested that the reporting forms be able to track that lines leased from non-CTPs are not subject to the access line fee under HB 1777 in order to avoid giving cities the misimpression that payment will be made on every single access line that is reported.

At the public hearing, CLEC Coalition explained that every access line that is counted and reported is not necessarily going to be subject to the access line fee under HB 1777. For example, CLEC Coalition described a situation where a company leases capacity from a non-certificated dark fiber provider that is already paying municipal compensation pursuant to some sort of agreement. Similarly, CLEC Coalition mentioned the situation in which a CTP leases capacity from a cable company that, pursuant to the terms of its cable franchise, is already paying municipal compensation for rights-of-way use. AT&T concurred with these comments, adding that, in particular, leased capacity from a cable company should not be subject to fees under HB 1777 because the municipality has already been fully compensated for the use of the rights-of-way through the cable provider.

A. Clarification of facilities vs. capacity

The commission clarifies that leasing capacity is akin to leasing facilities and therefore, access lines associated with a lease of either facilities or capacity should be reported. The commission has added clarifying language to subsection (g)(2)(A)(iv) stating that a CTP shall not differentiate between capacity and facilities leased or resold in reporting its access line count. This ensures that all lines are accurately reported. However, questions arise when capacity or facilities are leased from non-CTPs, as HB 1777 does not govern such providers. These issues are addressed under parts B and C of the commission's response.

B. Leasing dark (unlit) fiber

Although both are non-CTPs, the commission distinguishes between non-CTPs that provide dark (unlit) fiber/infrastructure only, and other non-CTPs, such as cable providers. In an effort to avoid a double counting of dark (unlit) fiber/infrastructure, (which could result in a double pass-through of municipal fees for the same access line if the municipality assesses franchise fees on non-CTPs), the commission determines that dark (unlit) fiber/infrastructure is not subject to counting under HB 1777 when that dark (unlit) fiber/infrastructure is resold to a CTP. This analysis is based on the fact that a CTP is not, itself, the end user of the dark (unlit) fiber/infrastructure. Consistent with the commission's treatment of other access lines leased, sold or otherwise conveyed to CTPs, the trigger for the HB 1777 counting and compensation thereof is when an access line is provided to the ultimate end-use customer. The commission also clarifies that when a CTP leases dark (unlit) fiber/infrastructure from a non-CTP, extends it to the end-use customer, "lights" the fiber, and provides switched, non-switched or PBX-type services (resulting in access lines consistent with the definition of the Local Government Code, §283.002(1)), then those access lines shall be counted under HB 1777. The commission revises subsection (d)(2)(E) as follows: "Where dark (unlit) fiber is provided to an end-use customer who then lights it, the line shall be counted as a private line, by default, unless it is evident that it is used for providing switched services."

C. Leasing facilities or capacity from non-CTPs such as cable providers

The commission's analysis is different as to leasing facilities or capacity from non-CTPs such as cable providers. Providing local exchange services over a cable network is an issue of shared use of the same infrastructure for two different types of services. HB 1777 establishes a uniform method for compensating municipalities for the use of the public right-of-way by CTPs using the end-use customer as a "proxy" for counting access lines. Moreover, HB 1777 does not exclude any class of access lines provided by CTPs, whether or not that class of access lines has been provided over cable lines. In fact, the definition of access lines in Local Government Code §283.002(1), uses broad terms such as "transmission path" and "transmission media," without limitation. Further, the compensation mechanism for a cable network (percentage of gross receipts) is not consistent with the fee-per-line methodology outlined in HB 1777. Accordingly, the commission determines that cable lines used by a CTP that have switched transmission paths, meet the definition of access lines under the Local Government Code §283.002(1). The same rationale applies to cable lines that are used by CTPs for providing non-switched telephone or other circuit or central office-based PBX-type services.

The commission concludes that any transmission medium that meets the definition of access lines is subject to counting and compensation under HB 1777 regardless of whether such medium compensated a municipality for the use of the right-of-way for purposes outside HB 1777. Short of a legislative directive on this issue, the commission believes that this interpretation is consistent with HB 1777. However, to the extent that the FCC determines that certain transmission media do not meet the definition of access lines under the Local Government Code §283.002(1) and do not deliver local exchange services, the commission reserves the right to amend its analysis of this issue.

In response to overall concerns about this issue outlined in the sections above, the commission revises subsection (g)(2)(A)(iv), as follows: "A CTP shall not make a distinction between facilities and capacity leased or resold in reporting its access line count."

Section 26.465(g)(2)(A)(i)

Proposed §26.465(g)(2)(A)(i) sets forth the deadlines for the initial reporting of access line count from CTPs. CTPs are required to report access line counts as of December 1, 1999 with certain exceptions no later than January 3, 2000 in a commission-approved form.

SWBT requested an additional two weeks for the initial reporting due date of January 3, 2000 because of billing cycles and the holidays; SWBT maintained that it cannot obtain data for the billing period ending November 30, 1999 until December 15, 1999, at the earliest. MCIW raised concerns about meeting the proposed deadline, in part because of internal definitions for access lines that differ from commission's adopted definitions, and in part because of Y2K issues. AT&T and GTESW echoed SWBT's request for extension; GTESW proposed a January 21 deadline.

Cities, supported by Dallas and TCCFUI, raised concerns that the requirement in the proposed §26.465(g)(2)(A)(i) to report line counts by December 1, 1999 does not comport with the statute's intent. Cities argued that, because the base amount is derived from the 1998 revenue levels, to calculate a rate based on 1999 access line numbers effectively eliminates the revenue growth that a city would have received during 1999. There is no indication the Legislature intended cities to suffer such a loss, Cities asserted.

The commission agrees with the commenters, and has extended the initial reporting date to January 24, 2000. The commission agrees with the comments offered by Cities, Dallas, and TCCFUI. It is appropriate to associate the line counting period with the base amount reporting period, which was calendar year 1998. Therefore, the commission revises subsection (g)(2)(A)(i) to require CTPs to provide a 1998 access line count to the extent possible. The commission will develop an alternative method to derive 1998 line counts from 1999 line count information where a CTP is unable to report a 1998 count. This methodology will be discussed in the rates and compensation rule, §26.467.

Section 26.465(g)(2)(A)(iii)

Proposed §26.465(g)(2)(A)(iii) requires that in the event a municipality has provided notice to the CTP by November 15, 1999 of its election to use the statewide average rate method, the CTP shall report the access line count as of December 31, 1998.

Several cities complained about being required to notify their CTPs by November 15, 1999 if they wish to choose the statewide average. Dallas said this notification is not found in the statute, is unnecessary, and further complicates a city's decision making process. Further, Dallas pointed out that cities will not know their access line estimates on that date and may not know the CTPs that are operating in their city. An additional concern of Dallas' was that cities would not have sufficient information to make their decision to use the statewide average by November 15, 1999. Garland/San Angelo noted that this requirement is unworkable because this rule will not be final until two weeks after the November l5th deadline. Alternatively, Garland/San Angelo suggested that the CTPs obtain the base amount forms for the municipalities in which they operate to determine for themselves which cities have selected the statewide average. SWBT proposed deleting this subsection altogether.

TCCFUI contended that the November 15, 1999 deadline puts cities at a substantial disadvantage because it is prior to the December 1 deadline for the CTP to notify cities of its decision to terminate its existing contracts. A CTP would be able to assess if they were better off terminating or continuing the existing franchise based on the cities' election. TCCFUI favored a December 1, 1999 deadline instead to eliminate this problem. AT&T requested clarification regarding the requirement that the adequate notice to CTPs be consistent with subsection (k) as it is not clear what requirements this cross reference refers to.

SWBT commented that they do not have and cannot provide an access line count as of December 31, 1998. SWBT explained that it did not count "access lines" in 1998 for all cities to which it paid municipal fees; some cities assessed fees on a flat-sum basis and some on a gross receipts basis. But even in cities on a fee per line system, the counting method was not completely consistent with the commission's counting methodology. Similarly, GTESW pointed out that CTPs, including GTESW, may not be able to recreate December 31,1998 access line counts, as defined under HB 1777 and commission rules. Both GTESW and SWBT recommended that the commission approximate the 1998 line count from the 1999 count that will be provided, by subtracting a reasonable estimate of growth.

At the public hearing, SWBT revised its position, stating that, based on the revised categories of access lines, SWBT might be able to produce a 1998 line count for Categories 1 and 2, residential and non-residential switched access lines. Cities emphasized the need to be able to match up 1998 revenues to 1998 line counts.

The commission agrees with Garland/San Angelo that it is unworkable to require municipalities to report their base amount decision by November 15, 1999 because the rule will not be final until after December 16, 1999. Further, the commission has amended the rule in subsection (g)(2)(A)(i) to add that, whenever possible, a CTP shall provide a 1998 line count for all municipalities. Since the commission's revised rules require the CTPs to provide a 1998 access line count for all municipalities, it is not necessary for municipalities that choose the statewide average option to notify CTPs of their option. Accordingly, the commission deletes the reference to the municipality's notice to select statewide average in subsection (g)(2)(A)(iii). The commission understands the difficulty for certain CTPs in providing a 1998 access line count. Where a CTP is unable to report a 1998 count, the commission will develop an alternative method to derive 1998 line counts from 1999 line count information. This methodology will be discussed in the rates and compensation rule, §26.467. The commission has added language to subsection (g)(2)(A)(iii) that would allow CTPs to file a good cause exemption for reporting a 1999 access line count.

Section 26.465(g)(2)(B)(i)-Subsequent Reporting

Proposed §26.465(g)(2)(B) outlined subsequent reporting procedures for CTPs. In particular, proposed §26.465(g)(2)(B)(i) requires quarterly reporting of access lines with the first report due 30 days following the end of the second quarter of 2000. GTESW commented that the first report will contain only one month of data (June). This assumption is based on the fact that quarterly reporting requirements will begin when CTPs begin billing the access line fees, which is expected to be in the second quarter, or approximately June 1; the first quarterly report will be for the second quarter of 2000, filed in August 2000, and may contain only June access line information, while the subsequent report will include three months of data. SWBT suggested that the reporting requirement should commence with the quarterly payments to municipalities, which is 45 days after the end of the quarter, and should include data beginning with the month in which the CTP implements rates.

The commission disagrees with GTESW and disagrees, in part, with SWBT. The commission believes the first access line report should contain three months of access line counts for the second calendar quarter of 2000. For administrative simplicity, subsequent access line reports should be based on calendar quarters for all CTPs rather than the date of implementation by CTPs, which could vary. However, consistent with SWBT's suggestion, the commission will amend the rule in subsection (g)(2)(B)(i) for the reports to be provided 45 days after the end of each calendar quarter and this date shall be consistent with the municipal payment date. Therefore, the first report shall be due no later than August 15, 2000. The first payments from CTPs pursuant to HB 1777 shall also coincide with this date. The first payments should reflect compensation for access line count reported for the second quarter. The commission has also added language to subsection (g)(2)(B)(ii) to clarify when the access line reports are due to the commission and when the payments associated with those access lines are due to the municipality.

Section 26.465(g)(2)(B)(ii)

Proposed §26.465(g)(2)(B)(ii) states that a provider may not include in its monthly count of access lines any access lines that are resold, leased, or otherwise provided to another CTP if the provider receives adequate proof that the provider leasing or purchasing the access lines will include the access lines in its own monthly count. Adequate proof shall consist of a notarized statement of notice prepared consistent with subsection (k) of this section.

Garland/San Angelo and GTESW objected to this subsection of the rule. Garland/San Angelo suggested that a description of the circumstances under which the commission would ask a CTP to identify either access lines that are resold or unbundled or the identity of the reseller or unbundled facilities should be added to this subsection. Garland/San Angelo also pointed out that the only subsequent reporting requirements in the Local Government Code are the reports from the CTPs to the commission. They are concerned that there is no requirement for the CTP to give information to the municipality. They point out that the only report required to be filed with municipalities is the quarterly report, and then, only if requested by the municipality. Municipalities, according to Garland/San Angelo, should be able to review all access line information, including resold and unbundled services, to verify that all access lines in the municipality have been accounted for. Therefore, Garland/San Angelo proposed language to state the commission would request such information if it receives a request from a municipality. In contrast, GTESW opposed requiring the underlying provider to report access lines that are resold to a CLEC because it would be a burdensome and costly effort since this information is not readily available.

The commission agrees with Garland/San Angelo, in part. The commission believes that access line count information should be reported to the commission each quarter. The commission, however, does not believe that quarterly reporting from the CTPs should include all lines that are resold, unless a reseller and the underlying carrier have reached an agreement that the underlying CTP will provide such information on its behalf. Local Government Code §283.056(C) gives specific authority to a municipality to conduct a review of the provider's access line count. Should the commission receive a request from a municipality for a review of a CTP's access line count, the commission will then request a CTP to provide information on resold lines. However, requiring the CTPs to provide such information as a matter of routine would confuse the quarterly reporting process and be administratively burdensome. Also, the commission believes that GTESW's concern is unfounded since CTPs only have to report such information to the extent it is available. The commission has made no changes to subsection (g)(2)(B)(iii).

Section 26.465(g)(2)(B)(vi)

Proposed §26.465(g)(2)(B)(vi) required each CTP to provide each affected municipality with a copy of the report required by this subsection.

AT&T and SWBT requested that this subsection be clarified to state that the CTP will provide to the municipality a report of its own access lines, but not the access lines of other municipalities.

The commission agrees with the commenters, and has revised the rule clarifying that a CTP need only provide to a municipality those access line counts that are attributable to that municipality.

Section 26.465(h)-Exemption

Proposed §26.465(h) delineates the exemptions permitted under the rule.

NorthPoint opposed this subsection, which would exempt any CTP that continues under an existing franchise agreement or ordinance from the subsequent reporting requirements. Because all CTPs are subject to the initial reporting provisions under subsection (g)(2)(A), there would seem to be a benefit to requiring all CTPs to continue updating their reports on a quarterly basis. Further, NorthPoint suggested that encompassing all CTPs in the subsequent reporting requirements would eliminate possible confusion as to an otherwise exempt CTP's obligation to report access lines provided by resale or unbundled facilities.

The commission believes that requesting CTPs that have unterminated agreements to report quarterly access line count is unnecessary; consistent with the Local Government Code §283.054(a), a provider is not governed by HB 1777 until that provider actually terminates its agreement. Further, such counts would actually confuse the quarterly reporting process. All CTPs were required to report their initial access line count so that the commission could establish statewide average rates and fee-per-access line rates for all municipalities. On the other hand, the purpose of the subsequent reporting is to ensure that municipalities receive adequate compensation from CTPs who have terminated their franchise agreements. Therefore the commission declines to include subsequent reporting for those CTPs that have unterminated franchise agreement with municipalities.

Section 26.465(j)-Proprietary or confidential information.

Proposed §26.465(j) set forth the terms and conditions for the treatment of proprietary or confidential information filed pursuant to this section.

NorthPoint opposed provisions in subsection (j)(1) which state that information filed by CTPs is presumed public and that a CTP has the burden of establishing that the information is proprietary or confidential. NorthPoint argued that this is not consistent with the commission's treatment of similar material in other proceedings. The access line reports required of CTPs are highly confidential and inherently fall under the confidential and competitive information exceptions to the Government Code, Chapter 552. NorthPoint proposed that subsection (j) should be amended to provide that the access line reports filed under this rule are deemed confidential. NorthPoint also mentioned that, under the procedures set forth in the Open Records Act, at most, only aggregate numbers of access lines for the State should ever be disclosed to the public following an adverse commission or court order. Garland/San Angelo mentioned that the Open Records Act is now entitled the Public Information Act and suggested correcting this reference within subsections (j)(2) and (j)(3).

GTESW, SWBT, and MCIW also objected to the proposed language; AT&T voiced shared concerns at the public hearing. GTESW requested that the rule indicate that the information is deemed proprietary because it can be used by competitors. Further, GTESW noted that the commission must provide the CTP with notice of requests for access line data in a timely manner in order for the CTP to have the maximum opportunity to seek injunctive release. SWBT requested that the subsection be amended to clarify that the information provided to the commission is exempt from disclosure. Local Government Code §283.005 makes clear that the commission and municipalities are required to maintain the confidentiality of all such information the CTPs claim to be confidential as is necessary to implement the provisions of HB 1777 in accordance with PURA §52.207. Section 52.207 requires the commission to maintain the confidentiality of information that is claimed to be confidential for competitive purposes. Section 52.207 also exempts the confidential information from disclosure under the Government Code, Chapter 552. SWBT pointed out that it is this claim of confidentiality that establishes the statutory exemption from disclosure. MCIW urged the commission to remove any language that suggests the line counts are subject to public disclosure, as this information is highly confidential and proprietary.

At the public hearing, Cities questioned whether city councils would be able to discuss line count information in a public forum. SWBT argued that even aggregated information should be kept confidential and private, even in a public meeting. TML explained the nature and limitations of the Open Meetings Act, indicating that free speech cannot be abridged. Dallas also discussed the need to make recommendations, at least as to allocation, in an open meeting. In smaller cities, with only one provider, the problem is magnified.

The commission agrees with Garland/San Angelo and will correct references to the Government Code, Chapter 552. Further, the commission agrees with the various commenters and revises this subsection by adding new paragraphs (2) and (4) as follows:

(2) The commission shall maintain the confidentiality of the information provided by certificated telecommunications providers in accordance with the Public Utility Regulatory Act (PURA) §52.207.

(4) Information provided to municipalities under the Local Government Code, Chapter 283, shall be governed by existing confidentiality procedures which have been established by the commission in compliance with PURA §52.207.

Section 26.465(k)-Attestation.

Proposed §26.465(k) sets forth the rules of attestation for filings made pursuant to this section. Proposed subsection (k) requires the access line reports to be filed pursuant to the commission's procedural rules, and to be attested to by an officer or authorized representative of the CTP. Proposed subsection (g)(2)(A)(iii) by reference also requires the municipalities to give notice to CTPs regarding their election to use the statewide average for determining their base amount to comply with this subsection. Garland/San Angelo suggests that municipalities should not be required to comply with subsection (k) because the requirements are onerous, not necessary, and inappropriate for notice from a municipality to a CTP.

The commission has deleted proposed §26.465(g)(2)(A)(iii) which required municipalities to notify each CTP by November 15 regarding whether the municipality elected to use the statewide average rate. No change to this section to address the form of such notification is needed.

Section 26.465(l)-Reporting of access lines by means of resold services or unbundled facilities to another CTP.

Proposed §26.465(l) addresses the reporting of access lines by means of resold services or unbundled facilities to another CTP. The last sentence of subsection (l) states that "Nothing in this subsection shall prevent a CTP reporting another CTP's access line count from charging an appropriate, tariffed administrative fee for such service."

NorthPoint sought clarification of, and recommended specific language for, the last sentence of subsection (l), to indicate that a CTP may only charge an administrative fee when it is required to report access lines provided by resale or unbundled facilities and the provider leasing or purchasing the access lines has not given the CTP adequate proof that it will be submitting its own monthly count. GTESW commented that the administrative burden of requiring an underlying provider to account for a competitor's access lines is incomprehensible. GTESW asserted that such a requirement would be onerous and goes beyond normal business requirements because GTESW does business in approximately 500 jurisdictions. Further, since GTESW could not report lines that are multiplexed by the reseller, they would not be fairly assessed a ROW fee. GTESW stated that the access line count, if required to be reported by the CTP, can be nothing greater than what is reflected in the CTP's billing records. SWBT requested that the subsection be amended to require CTPs that elect to have the underlying CTP report or pay their access line count or fees to provide the underlying CTP all required information, in properly verified and authenticated form, together with a certified check made out to the municipality for all sums due for ROW compensation, within 30 days after the end of the quarter. SWBT suggested that this approach will allow the underlying CTP to meet the 45-day deadline for getting the report to the commission and making payment to the municipalities. SWBT stated that if the CTP has to do anything other than pass on the information and payments from the CLECs, this rule will have to be substantially amended. Alternatively, if the rule requires the ILECs to count, assess, report and pay on access lines that CLECs actually provide to end users, a result SWBT opposes and believes is contrary to the Local Government Code, Chapter 283, it must also require the CLECs to provide the necessary information for the ILECs to perform the task. SWBT recommended that the CLECs must provide in certified and electronic format the following information: 1) end user addresses; 2) services provided; 3) class (e.g. residential or non-residential) and commission category of service; and 4) tax authority information for the municipalities to be paid (TAR). Further, SWBT asserted that this information must be provided on the embedded base of UNEs and resold services.

At the public hearing, several parties responded to the question of how the municipal fee should be paid in a line-sharing situation, assuming that only one fee is paid despite multiple services being provided over the same line. TEXALTEL suggested that the ground rule should be that whoever has the facilities in the ROW pays the fee. TEXALTEL argued that this analysis applies even where the underlying facilities belong to a cable company, maintaining that, where payment is being made under a cable franchise, no additional payment is owed for a telephone franchise. TEXALTEL also mentioned that where CTPs providing services over a line have elected to pay their own fees, then that reseller should pay the municipality based on the services the reseller provides. Thus, the reseller's election shifts the responsibility for payment of the fees from the owner of the facility to the reseller. But absent such an election by a reseller, TEXALTEL indicated that a facility owner might be responsible for paying multiple fees for all the services provided over the lines.

AT&T reiterated its earlier arguments concerning the burden on the ROW as the basis for their analysis that where municipalities have been compensated for the use of the ROW through the underlying facilities, whether cable facilities or telecommunications facilities, there is no additional burden to trigger the assessment of access line fees under HB 1777. AT&T asserted this same analysis should apply whether the mixed use involves a single CTP providing local exchange services or a combination of services, or whether the services are provided by different affiliates.

Cities responded that municipalities are to be paid on every line that is reported. Cities highlighted the fact that, as to cable providers, federal law requires a separate agreement or certification for a cable provider to provide telecommunications services. Once certificated, such a provider's lines would be subject to HB 1777 and they would have to pay municipal compensation. City of El Paso opined that to allow only a single fee to be assessed on a multiple-use line would not just create a loophole, but would dissolve the compensation scheme set up by HB 1777. Cities also raised concerns that allowing certain access lines to be assessed fees while excluding others does not create a competitively neutral compensation scheme.

The commission disagrees with NorthPoint that the commission should restrict CTPs' ability to charge reasonable administrative fees based only on certain circumstances. The commission's rules do not make it mandatory for CTPs to charge an administrative fee for reporting CLEC access lines and possibly remitting municipal fee payments; the determination of counting lines and paying fees between CTPs is an issue of inter-carrier compensation that must be developed in a case-specific context between CTPs. The commission agrees with GTESW that when UNE providers offer multiplexed services, it is impossible for the underlying provider to know the number of the lines being provided and more importantly, the category of these access lines. Therefore, this information must be provided by the CLEC that has the actual knowledge of the retail end-use customers. Again, whether the CLECs compensate the municipality directly or through the underlying carrier is not up to the commission to decide. As noted earlier, it is an inter-carrier compensation issue and is best left up the individual CTPs to make a business decision on this issue. SWBT has outlined specific details on what it takes for an ILEC to report access lines on behalf of a CLEC. While the commission agrees with the format proposed by SWBT, it does not believe that such specific details need to be reflected in rule language. These requirements can vary from one CTP to another and imposing one set of formats may reduce the flexibility which some CTPs may desire. Therefore, the commission has not made any changes to §26.465(l).

Section 26.465(m)-Commission review of the definition of access line.

Consistent with the Local Government Code, Chapter 283, the rule requires that the commission determine whether changes in technology, facilities, or competitive or market conditions justify a modification of the adoption of the definition of access line. Garland/San Angelo suggested language to clarify the commission's authority to modify the statutory definition of "access line."

The commission has added language to subsection (m) citing statutory authority to review the definition of access line.

Other comments regarding definitions

Dallas commented that the terms "affiliates" and "interoffice transport" are undefined. Dallas proposed that "interoffice transport" be defined as "any line which is owned by a CTP to connect to its own facilities."

The commission rejects Dallas's definition of interoffice transport as it is more narrow than that contemplated under the statute. The commission believes it is unnecessary to adopt a definition of interoffice transport, given the fact that the commission's rules provide detailed and specific guidance on what types of lines must be counted and what types are excluded. The commission notes that the term "affiliates" has been commonly understood by its plain meaning and no other commenters have raised this as an issue. Therefore, the commission declines to add a definition for the term "affiliates".

In adopting this section, the commission makes other minor modifications for the purposes of clarifying its intent. All comments, including those not specifically referenced herein, were fully considered by the commission.

This new rule is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998) (PURA), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction. This rule is also authorized by House Bill 1777, Act of May 25, 1999, 76th Legislature, Regular Session, chapter 840, 1999 Texas Session Law Service 3499 (Vernon) (to be codified as an amendment to the Local Government Code §283.055) which provides that not later than March 1, 2000, the commission shall establish rates per access line by category for the use of a public right-of-way by certificated telecommunications providers in each municipality and the statewide average of those rates. The rates shall be applied to the total number of access lines by category in the municipality.

Cross Reference to Statutes: Public Utility Regulatory Act §14.002 and Local Government Code §283.055.

§26.465. Methodology for Counting Access Lines and Reporting Requirements for Certificated Telecommunications Providers.

(a) Purpose. This section establishes a uniform method for counting access lines within a municipality by category as provided by §26.461 of this title (relating to Access Line Categories), sets forth relevant reporting requirements, and sets forth certain reseller obligations under the Local Government Code, Chapter 283.

(b) Application. This section applies to all certificated telecommunications providers (CTPs) in the State of Texas.

(c) Definitions. The following words and terms when used in this section, shall have the following meaning, unless the context clearly indicates otherwise.

(1) Customer–The retail end-use customer.

(2) Transmission path–A path within the transmission media that allows the delivery of switched local exchange service.

(A) Each individual circuit-switched service shall constitute a single transmission path.

(B) Where services are offered as part of a bundled group of services, each switched service in that bundled group of services shall constitute a single transmission path.

(C) Only those services that require the use of a circuit-switch shall constitute a switched service.

(D) Services that constitute vertical features of a switched service, such as call waiting, caller-ID, etc., that do not require a separate switched path, do not constitute a transmission path.

(E) Where a service or technology is channelized by the CTP and results in a separate switched path for each channel, each such channel shall constitute a single transmission path.

(3) Wireless provider–A provider of commercial mobile service as defined by §332(d), Communications Act of 1934 (47 U.S.C. §151 *et seq.*), Federal Communications Commission rules,

and the Omnibus Budget Reconciliation Act of 1993 (Public Law 103-66).

(d) Methodology for counting access lines. A CTP's access line count shall be the sum of all lines counted pursuant to paragraphs (1), (2), and (3) of this subsection, and shall be consistent with subsections (e), (f) and (g) of this section.

(1) Switched transmission paths and services.

(A) The CTP shall determine the total number of switched transmission paths, and shall take into account the number of switched services provided and the number of channels used where a service or technology is channelized.

(B) All switched services shall be counted in the same manner regardless of the type of transmission media used to provide the service.

(C) If the transmission path crosses more than one municipality, the line shall be counted in, and attributed to, the municipality where the end-use customer is located.

(2) Nonswitched telecommunications services or private lines.

(A) Each circuit used to provide nonswitched telecommunications services or private lines to an end-use customer, shall be considered to have two termination points, one on each customer location identified by the customer and served by the circuit.

(B) The CTP shall count nonswitched telecommunications services or private lines by totaling the number of terminating points within a municipality.

(C) A nonswitched telecommunications service shall be counted in the same manner regardless of the type of transmission media used to provide that service.

(D) A terminating point shall be counted in, and attributed to, the municipality where that point is located. In the event a CTP is not able to identify the physical location of the terminating point, that point shall be attributed to the municipality identified by the CTP's billing systems.

(E) Where dark (unlit) fiber is provided to an end-use customer who then lights it, the line shall be counted as a private line, by default, unless it is evident that it is used for providing switched services.

(3) Central office based PBX-type services. The CTP shall count one access line for every ten stations served.

(e) Lines to be counted. A CTP shall count the following access lines:

(1) all access lines provided to a retail end-use customer;

(2) all access lines provided as a retail service to other CTPs and resellers for their own end-use;

(3) all access lines provided as a retail service to wireless telecommunication providers and interexchange carriers (IXCs) for their own end-use;

(4) all access lines a CTP provides as employee concession lines and other similar types of lines;

(5) all access lines provided as a retail service to a CTP's wireless and IXC affiliates for their own end-use, and all access lines provided as a retail service to any other affiliate for their own end-use;

(6) dark fiber, to the extent it is provided as a service or is resold by a CTP and shall exclude lines sold and resold by non-CTPs;

(7) any other lines meeting the definition of access line as set forth in §26.461 of this title; and

(8) Lifeline and Tel-assistance lines.

(f) Lines not to be counted. A CTP shall not count the following lines:

(1) all lines that do not terminate at an end-use customer's premises;

(2) lines used by providers who are not end-use customers such as CTP, wireless provider, or IXC for interoffice transport, or back-haul facilities used to connect such providers' telecommunications equipment;

(3) lines used by a CTP's wireless and IXC affiliates who are not end-use customers, for interoffice transport, or back-haul facilities used to connect such affiliates' telecommunications equipment;

(4) lines used by any other affiliate of a CTP for interoffice transport; and

(5) any other lines that do not meet the definition of access line as set forth in §26.461 of this title.

(g) Reporting procedures and requirements.

(1) Who shall file. The record keeping, reporting and filing requirements listed in this section shall apply to all CTPs in the State of Texas.

(2) Reporting requirements. Unless otherwise specified, periodic reporting shall be consistent with this subsection and subsection (d) of this section.

(A) Initial reporting.

(i) No later than January 24, 2000, a CTP shall file its access line count using the commission-approved *Form for Counting Access Line* or *Program for Counting Access Lines* with the commission. The CTP shall report the access line count as of December 31, 1998, except as provided in clause (iii) of this subparagraph.

(ii) A CTP shall not include in its initial report any access lines that are resold, leased, or otherwise provided to a CTP, unless it has agreed to a request from another CTP to include resold or leased lines as part of its access line report.

(iii) A CTP that cannot file access line count as of December 31, 1998 shall file request for good cause exemption and shall file the most recent access line count available for December, 1999.

(iv) A CTP shall not make a distinction between facilities and capacity leased or resold in reporting its access line count.

(B) Subsequent reporting.

(i) Each CTP shall file with the commission a quarterly report beginning the second quarter of the year 2000, showing the number of access lines, including access lines by category, that the CTP has within each municipality at the end of each month of the quarter. The report shall be filed no later than 45 days after the end of the quarter using the commission-approved Form for Quarterly Reporting of Access Lines and shall coincide with the payment to a municipality.

(ii) The first report shall be due to the commission no later than August 15, 2000 and shall include access line for the second calendar quarter of 2000 and shall coincide with the first payment to a municipality pursuant to the Local Government Code, Chapter 283.

(iii) Except as provided in clause (iv) of this subparagraph, on request of the commission, and to the extent available, the report filed under clause (i) of this subparagraph shall identify, as part of the CTP's monthly access line count, the access lines that are provided by means of resold services or unbundled facilities to another CTP who is not an end-use customer, and the identity of the CTPs obtaining the resold services or unbundled facilities to provide services to customers.

(iv) A CTP may not include in its monthly count of access lines any access lines that are resold, leased, or otherwise provided to another CTP if the CTP receives adequate proof that the CTP leasing or purchasing the access lines will include the access lines in its own monthly count. Adequate proof shall consist of a notarized statement prepared consistent with subsection (k) of this section.

(v) The CTP shall respond to any request for additional information from the commission within 30 days from receipt of the request.

(vi) Reports required under this subsection may be used by the commission only to verify the number of access lines that serve customer premises within a municipality.

(vii) On request from a municipality, and subject to the confidentiality protections of subsection (j) of this section, each CTP shall provide each affected municipality with a copy of the municipality's access line count.

(h) Exemption. Any CTP that does not terminate a franchise agreement or obligation under an existing ordinance shall be exempted from subsequent reporting pursuant to subsection (g)(2)(B) of this section unless and until the franchise agreement is terminated or expires on its own terms. Any CTP that fails to provide notice to the commission and the affected municipality by December 1, 1999 that it elects to terminate its franchise agreement or obligation under an existing ordinance, shall be deemed to continue under the terms of the existing ordinance. Upon expiration or termination of the existing franchise agreement or ordinance by its own terms, a CTP is subject to the terms of this section.

(i) Maintenance and location of records. A CTP shall maintain all records, books, accounts, or memoranda relating to access lines deployed in a municipality in a manner which allows for easy identification and review by the commission and, as appropriate, by the relevant municipality. The books and records for each access line count shall be maintained for a period of no less than three years.

(j) Proprietary or confidential information.

(1) The CTP shall file with the commission the information required by this section regardless of whether this information is confidential. For information that the CTP alleges is confidential and/or proprietary under law, the CTP shall file a complete list of the information that the CTP alleges is confidential. For each document or portion thereof claimed to be confidential, the CTP shall cite the specific provision(s) of the Texas Government Code, Chapter 552, that the CTP relies to assert that the information is exempt from public disclosure. The commission shall treat as confidential the specific information identified by the CTP as confidential until such time as a determination is made by the commission, the Attorney General, or a court of competent jurisdiction that the information is not entitled to confidential treatment.

(2) The commission shall maintain the confidentiality of the information provided by CTPs, in accordance with the Public Utility Regulatory Act (PURA) §52.207.

(3) If the CTP does not claim confidential treatment for a document or portions thereof, then the information will be treated as public information. A claim of confidentiality by a CTP does not bind the commission to find that any information is proprietary and/or confidential under law, or alter the burden of proof on that issue.

(4) Information provided to municipalities under the Local Government Code, Chapter 283, shall be governed by existing confidentiality procedures which have been established by the commission in compliance with PURA §52.207.

(5) The commission shall notify a CTP that claims its filing as confidential of any request for such information.

(k) Report attestation. All filings with the commission pursuant to this section shall be in accordance with §22.71 of this title (relating to Filing of Pleadings, Documents and Other Materials) and §22.72 of this title (relating to Formal Requisites of Pleadings and Documents to Be Filed With the Commission). The filings shall be attested to by an officer or authorized representative of the CTP under whose direction the report is prepared or other official in responsible charge of the entity in accordance with §26.71(d) of this title (relating to General Procedures, Requirements and Penalties). The filings shall include a certified statement from an authorized officer or duly authorized representative of the CTP stating that the information contained in the report is true and correct to the best of the officer's or representative's knowledge and belief after inquiry.

(l) Reporting of access lines that have been provided by means of resold services or unbundled facilities to another CTP. This subsection applies only to a CTP reporting access lines under subsection (g) of this section, that are provided by means of resold services or unbundled facilities to another CTP who is not an end-use customer. Nothing in this subsection shall prevent a CTP reporting another CTP's access line count from charging an appropriate, tariffed administrative fee for such service.

(m) Commission review of the definition of access line.

(1) Pursuant to the Local Government Code §283.003, not later than September 1, 2002, the commission shall determine whether changes in technology, facilities, or competitive or market conditions justify a modification of the adoption of the definition of "access line" provided by §26.461 of this title. The commission may not begin a review authorized by this subsection before March 1, 2002.

(2) As part of the proceeding described by paragraph (1) of this subsection, and as necessary after that proceeding, the commission by rule may modify the definition of "access line" as necessary to ensure competitive neutrality and nondiscriminatory application and to maintain consistent levels of compensation, as annually increased by growth in access lines within the municipalities.

(3) After September 1, 2002, the commission, on its own motion, shall make the determination required by this subsection at least once every three years.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 20, 1999.

TRD-9908894
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Effective date: January 9, 2000
Proposal publication date: October 8, 1999
For further information, please call: (512) 936-7308

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TITLE 28. INSURANCE

Part 1. TEXAS DEPARTMENT OF INSURANCE

Chapter 3. LIFE, ACCIDENT AND HEALTH INSURANCE AND ANNUITIES

Subchapter Z. EXEMPTION FROM REVIEW AND APPROVAL OF CERTAIN LIFE, ACCIDENT, HEALTH AND ANNUITY FORMS AND EXPEDITION OF REVIEW

28 TAC §3.4003

The Commissioner of Insurance adopts the repeal of §3.4003, concerning the list of forms in use for exemption of certain life, accident, health and annuity forms from review and approval requirements. The repeal is adopted without changes to the proposal as published in the October 15, 1999 issue of the *Texas Register* (24 TexReg 8903).

The repeal is necessary because the department already has authority in the Insurance Code, §38.001 (former Article 1.24), to request the information subject to §3.4003, as it is needed, rather than require companies to routinely submit it. Simultaneous to this repeal, adoption of amendments to §§3.4004, 3.4008 and 3.4020 are published elsewhere in this issue of the Texas Register.

The repeal of this section will reduce the amount of administrative time staff utilizes to review forms routinely submitted by companies, since the information can be requested on an as-needed basis pursuant to the provisions of the Insurance Code, §38.001 (former Article 1.24).

No comments were received regarding adoption of the repeal.

Repeal of §3.4003 is adopted pursuant to the Insurance Code Article 3.42 and §36.001 (former Article 1.03A). Article 3.42 provides that the department may adopt reasonable rules necessary to establish guidelines, procedures, methods, standards and criteria by which various and different types of forms and documents submitted to the department may receive expeditious treatment in the policy form review process. Section 36.001 provides that the Commissioner of Insurance may adopt rules and regulations to execute the duties and functions of the Texas Department of Insurance only as authorized by statute.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 20, 1999.

TRD-9908891
Lynda Nesenholtz
General Counsel and Chief Clerk
Texas Department of Insurance
Effective date: January 9, 2000
Proposal publication date: October 15, 1999
For further information, please call: (512) 463-6327

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28 TAC §§3.4004, 3.4008, 3.4020

The Commissioner of Insurance adopts amendments to §§3.4004, 3.4008, and 3.4020 relating to the exemption of certain life, accident, health and annuity forms from review and approval requirements. Section 3.4004 is adopted with changes to the proposed text as published in the October 15, 1999 issue of the *Texas Register* (24 TexReg 8903). Sections 3.4008 and 3.4020 are adopted without changes and will not be republished. Simultaneous to this adoption of the amendments, the commissioner is repealing §3.4003. Notice of the adopted repeal is published elsewhere in this issue of the Texas Register.

These amendments revise and update the categories of described forms for which the department has determined that the review and official action provisions of the Insurance Code, Article 3.42, are not required or necessary for the protection of the public, thereby enhancing the streamlining of the overall filing, review, and official action process for certain life, accident, health, and annuity forms. The amendments allow the department to maximize use of its resources and provide for a more judicious allocation of department resources.

The amendment to §3.4004 provides additions to the various categories of forms for which exemption from review applies, and also provides for exceptions to those exemptions. The amendments to §3.4008 add two new provisions which place the responsibility on companies to take corrective action and bring their forms previously filed as "exempt" into compliance when they discover any subsequent non-compliance of their forms whether such non-compliance is based upon a violation of a law of this state or of the United States, or whether the company subsequently realizes it filed a form as "exempt" which did not qualify for an exemption under §3.4004. The amendment to §3.4020 amends the reference to the "Small Employer Health Insurance Availability Act" in Figure 1, "TEXAS POLICY FORM CERTIFICATIONS" as revised by the 75th Legislative Session, to the "Health Insurance Portability and Availability Act."

The department has made changes to §3.4004 based upon public comments, as well as for clarification, punctuation, and consistency. The following revisions to the referenced sections were made: A change was made to §3.4004(c)(3) and (c)(4) to reinstate language that was proposed to be deleted in the proposed amendment to these sections. The sentence structure of subsection (c)(4) was also rearranged for clarity. The words "or the United States" were added to §3.4004(e) for consistency with subsections (a) and (c) of §3.4004.

The department's review of §3.4004(c)(4) revealed certain language found in the proposed amendments was inadvertently proposed for deletion and thus made the language misleading and inaccurate. The proposed deleted language in §3.4004(c)(4) would have allowed group annuities which contain persistency bonuses of any type, waiver of surrender charges, two-tier values, or a market value adjustment provision to be filed as exempt. This was not the department's intent. The department's intent was to exempt from review and approval those group annuities that may be classified as guaranteed investment contracts (GICs), synthetic GICs, funding plans and unallocated group annuities funding pension plans regardless of whether these products contained persistency bonuses of any type, waiver of surrender charges, two-tier values, or a market value adjustment provision. The proposed deleted language in §3.4004(c)(4) has been reinstated so that other group annuities which contain persistency bonuses of any type, waiver of surrender charges, two-tier values, or a market value adjustment provision must still be filed and reviewed for approval. The reinstated language pertaining to "wavier of surrender charges" in subsection (c)(4) was also changed to include the modifying language, "(except for death, disability or confinement in a hospital or nursing home)," to make it consistent with subsection (c)(3). Subparagraphs (A) and (B) of subsection (c)(3) were amended to reinstate language referencing subsection (c)(4) which was originally proposed for deletion.

The department anticipates there could be questions related to the language, "additional interest credits," in the amendments to subsections (b)(10) and (c)(3) of §3.4004. The department added the word "interest" to subsection (b)(10) to make it consistent with subsection (c)(3). Although the department did not make any other changes, this language should be interpreted to include additional increases in interest or other policy enhancements for an initial specified period of time, such as a 2% increase in interest or an additional specified amount credited for the first year only.

§3.4004(a): A commenter requested clarification of this section as to whether a company that has filed a form for approval in another state also must file the form for approval in Texas, even if the particular form is listed as exempt from the filing requirements under this section.

Agency response: In 1996, when the department proposed amendments to §3.4004(c)(3), the department received comments suggesting that there be a statement in the rules indicating that a company may, in particular instances, obtain review and approval of a policy form which otherwise is considered exempt. The specific example raised was that §3.4004 does not clarify that forms otherwise considered to be exempt from the review and approval process must nonetheless be reviewed and approved if they are going to be marketed by a Texas domestic company in a state other than Texas with laws that require such policies and forms to have received domiciliary approval before being marketed in that state. The department responded by revising subsections (a), (c), and (e) of §3.4004 to include language referring to the laws of another state requiring specific approval. As such, subsections (a), (c), and (e) allow, in lieu of exemption, approval in Texas if the laws of another state require a Texas domiciled company that wishes to market a product in that state to obtain specific approval in Texas before filing or marketing a product in that state.

Neither for nor Against: Manufacturer's Life Insurance Company (USA).

The amendments to the sections are adopted pursuant to the Insurance Code Article 3.42 and §36.001 (former Article 1.03A). Article 3.42(h) provides that the department may, by written order, exempt from the requirements of the article certain documents or forms and may adopt reasonable rules necessary to establish guidelines, procedures, methods, standards and criteria by which various and different types of forms and documents submitted to the department may receive expeditious treatment in the policy form review process. Section 36.001 authorizes the commissioner of insurance to promulgate and adopt rules and regulations for the conduct and execution of the duties and functions by the department.

§3.4004. Exempt Forms.

(a) Group and Individual Life Forms. The group and individual life insurance forms specified in this subsection are exempt from the review and approval requirements of the Insurance Code, Article 3.42, unless the forms are required by the laws of Texas, another state, or the United States, to be specifically approved or are otherwise excepted in subsection (b) of this section:

(1) group life insurance master policies, contracts, certificates, applications, enrollment forms, riders, amendments and endorsements applicable thereto, issued under authority of the Insurance Code Article 3.50, §1(1), (2), (3), (4), (5), (6)(b), (7), (7A), (8), (9), and (10), listed in subparagraphs (A) and (B) of this paragraph:

(A) term policies and riders; and

(B) cash value and endowment policies with no more than five death benefit and/or premium changes;

(2) any alternate face pages filed subsequent to the original approval of a policy for use with multiple employer trusteed arrangements as defined in Insurance Code, Article 3.50, §1(5);

(3) individual, joint life, and last survivor insurance forms, including applications, listed in subparagraphs (A)-(Q) of this paragraph:

(A) ordinary life;

(B) limited pay life with no more than five death benefit and/or premium changes;

(C) life paid up at specified ages with no more than five death benefit and/or premium changes;

(D) single premium life with no more than five death benefit changes;

(E) modified premium level death benefit life with no more than five premium changes;

(F) level premium life with no more than five death benefit changes;

(G) retirement income policies;

(H) level or decreasing term policies and riders;

(I) increasing term policies and riders;

(J) family plans;

(K) family income;

(L) family plan riders, including but not limited to children's term riders, dependent term riders, and spouse term riders;

(M) limited pay endowment with no more than five death benefit and/or premium changes;

(N) level premium endowment with no more than five death benefit changes;

(O) single premium endowment with no more than five death benefit changes;

(P) indeterminate premium policies with no more than five death benefit changes; and

(Q) variable life policies with a separate account only;

(4) rider forms listed in subparagraphs (A)-(K) of this paragraph:

(A) accidental death benefit riders;

(B) waiver of premium riders;

(C) guaranteed insurability riders;

(D) individual retirement accounts (IRA) (to include Roth and Simple IRA) riders;

(E) preliminary term riders;

(F) conversion riders;

(G) exchange riders;

(H) waiver of cost riders, including waiver of cost and monthly expense charge, and waiver of cost and premium payment;

(I) dividend option riders;

(J) additional insured riders; and

(K) additional insurance on base insured riders;

(5) endorsement forms listed in subparagraphs (A)-(K) of this paragraph:

(A) ORP endorsements;

(B) nontransferability endorsements;

(C) H.R. 10 endorsements;

(D) tax sheltered annuity endorsements;

(E) nonassignability endorsements;

(F) settlement option endorsements;

(G) individual retirement account endorsements (to include Roth and Simple IRA endorsements);

(H) unisex endorsements;

(I) loan endorsements;

(J) waiver of surrender charges on disability or confinement in a hospital or nursing home endorsements; and

(K) step-up or roll-up death benefit endorsements;

(6) limited refilings for life insurance which indicate only a change in the mortality table or interest rates for new issues under the policy form, or changes to the separate account for variable products.

(b) Exceptions. The provisions of subsection (a)(1) and (2) of this section shall not apply to any group or individual life insurance forms providing the types of coverages set out in paragraphs (1) - (12) of this subsection:

(1) universal life;

(2) universal related life;

(3) adjustable life;

(4) variable life with a fixed account;

(5) business value;

(6) any forms containing a market value adjustment;

(7) deposit term;

(8) forms subject to the Insurance Code article 3.53;

(9) any life insurance product used to fund prepaid funeral contracts;

(10) any form containing a persistency bonus provision, no-lapse premium provision, or other additional interest credit to the policy value provision (guaranteed or non-guaranteed), equity indexed provision, residual death benefit provision, accelerated death benefit provision, long-term care or other accident and health related benefit provision;

(11) applications for use with variable life or equity indexed life, or forms that contain a market value adjustment provision, a long-term care or other accident and health related benefit provision; or

(12) group life master policies, contracts, certificates, applications, enrollment forms, riders, amendments and endorsements applicable thereto, issued under the authority of Article 3.50, §1(6)(a), relating to discretionary groups.

(c) Group and Individual Annuity Forms. The group and individual annuity forms, including applications, specified in paragraphs (1)-(7) of this subsection are exempt from the review and approval requirements of the Insurance Code, Article 3.42, unless the forms are required by the laws of Texas, another state, or of the United States to be specifically approved or are otherwise excepted in subsection (d) of this section:

(1) single premium immediate annuities (including variable immediate annuities);

(2) deferred annuities used as structured settlement options;

(3) individual deferred annuities that do not include persistency bonuses or additional interest credits of any type, waiver of surrender charges (except for death, disability or confinement in a hospital or nursing home); two-tier values; or a market value adjustment:

(A) for purposes of this paragraph, and paragraph (4) of this subsection, "waiver of surrender charges" means a waiver of surrender charges which is applied to any amount greater than 10% of the surrender value;

(B) for purposes of this paragraph, and paragraph (4) of this subsection, "two tier values" means values on an annuity available at the maturity date of the contract which are different, depending on whether the value is taken from the contract in a lump sum or left with the issuer for periodic payments, regardless of whether the different values are available at issue or later;

(4) group annuities that do not include persistency bonuses or additional interest credits of any type, waiver of surrender charges (except for death, disability or confinement in a hospital or nursing home), two-tier values, or a market value adjustment; group annuities that are guaranteed investment contracts (GICs), synthetic GICs, funding agreements, and unallocated group annuities funding pension plans;

(5) limited refilings for annuity products which indicate only a change in the mortality table or interest rates for new issues under the policy form, or changes to the separate account for variable products;

(6) variable annuities with a separate account only, which do not include a provision for guaranteed living benefits; and

(7) reversionary annuities.

(d) Exceptions. The provisions of subsection (c) of this section shall not include any of the following annuity forms:

(1) annuities used to fund prepaid funeral contracts;

(2) variable annuities that contain guaranteed living benefit provisions;

(3) annuities that contain an equity indexed provision, long-term care or other accident and health related benefit provision;

(4) applications for use with variable annuities, equity indexed annuities, annuities that contain a market value adjustment provision, long-term care or other accident and health related provision;

(5) group annuity master policies, contracts, certificates, applications, enrollment forms, riders, amendments and endorsements applicable thereto, issued under the authority of Article 3.50, §1(6)(a), relating to discretionary groups.

(e) Group and Individual Accident and Health Forms. The group and individual accident and health insurance forms specified in paragraphs (1)-(3) of this subsection are exempt from the review and approval requirements of the Insurance Code, Article 3.42, unless the forms are required by the laws of Texas, another state, or the United States, to be specifically approved or are otherwise excepted in subsection (f) of this section:

(1) the group and blanket accident and health forms set out in subparagraphs (A)-(D) of this paragraph:

(A) any group accident and health master policies, contracts, certificates, applications, enrollment forms, riders, amendments, and endorsements applicable thereto issued under authority of the Insurance Code, Article 3.51-6, §1(a)(1) and (2); provided the forms issued under authority of the Insurance Code, Article 3.51-6, §1(a)(2), are exempt only if delivered or issued for delivery to a labor union or organization of labor unions;

(B) any blanket accident and health master policies, contracts, certificates, applications, enrollment forms, riders, amendments, and endorsements applicable thereto, issued under authority of the Insurance Code Article 3.51-6, §2(a)(1)-(8);

(C) any group master policies, contracts, certificates, applications, enrollment forms, riders, amendments, and endorsements applicable thereto, issued under the authority of the Insurance Code, Article 3.51-6, §1(a)(1), (2), or (3) providing Medicare Supplement coverage to an employer, multiple employer arrangement, or a labor union;

(D) any group master policies, contracts, certificates, applications, enrollment forms, riders, amendments, and endorsements applicable thereto, issued under the authority of the Insurance Code, Article 3.51-6, §1(a)(1) or (2) providing long term care coverage to a single employer or a labor union through a policy which is delivered or issued for delivery outside of Texas;

(2) group and individual accident and/or health policies, contracts, certificates, applications, enrollment forms, riders, amendments, endorsements, and related forms (including but not limited to outlines of coverage, notices, rates, and conditional receipts) applicable thereto, providing coverages set forth in subparagraphs (A)-(K) of this paragraph:

(A) accident only (including occupational accident and other specified accident);

(B) accidental death and dismemberment;

(C) dental;

(D) in-patient confinement and basic hospital expense coverages (including policies with coverage on an indemnity or expense-incurred basis)

(E) vision;

(F) specified disease (including cancer, heart attack, stroke, and other specifically named diseases);

(G) disability coverages (including but not limited to income replacement, key-man, buy/sell, and overhead expense);

(H) policies designed to provide conversion coverages;

(I) other permitted coverages which are designed to supplement other in-force health insurance, including Champus supplements;

(J) group stop loss/excess loss policies containing an attachment point of $5,000 or more; and

(K) prescription drug policies; and

(3) any alternate face pages filed subsequent to the original approval of a policy for use with multiple employer trusteed arrangements as defined in Insurance Code, Article 3.51-6, §1(a)(3).

(f) Exceptions. The provisions of subsection (e) of this section shall not apply to any of the insurance forms set out in paragraphs (1)-(6) of this section.

(1) The provisions of subsection (e)(2) of this section shall not apply to any group or individual health insurance policy which provides, on a comprehensive basis for illness and injury, a combination of hospital, medical, and surgical coverages, including but not limited to any major medical policies and any limited benefit hospital, medical, and surgical policies as defined in §3.3079 of this title (relating to Minimum Standards for Limited Benefit Coverage).

(2) The provisions of subsection (e)(1) and (2) of this section shall not apply to any Medicare supplement policies as defined in the Insurance Code, Article 3.74, except as specifically provided in subsection (e)(1)(C) of this section.

(3) The provisions of subsection (e)(1) and (2) of this section shall not apply to any long term care policies as defined in the Insurance Code, Article 3.70-12 (including but not limited to any policies providing nursing home or home health care coverages), except as specifically provided in subsection (e)(1)(D) of this section.

(4) The provisions of subsection (e)(1) and (2) of this section shall not apply to any forms which contain preferred provider benefit plan provisions as defined in §§3.3701 - 3.3706 of this title (relating to Preferred Provider Plans).

(5) The provisions of subsection (e)(1) and (2) of this section shall not apply to any group forms which are issued under the authority of Insurance Code, Article 3.51-6, §1(a)(6) (discretionary groups).

(6) The provisions of subsection (e)(2)(H) of this section shall not apply to any policy subject to the provisions of Subchapter F of this chapter (relating to Group Health Insurance Conversion Privilege), except for policies providing conversion from a policy included as an exempt form in this section.

(g) Copies of Previously Approved Forms. Any form not otherwise exempted under these sections that is an exact copy of a previously approved form is exempt from the review and approval requirements of the Insurance Code, Article 3.42. Such forms must be filed in accordance with and accompanied by the required certification as prescribed in Subchapter A of this chapter (relating to Filing of Policy Forms, Riders, Amendments and Endorsements for Life, Accident and Health Insurance and Annuities). The certification form required to be used in filing the certification is "TEXAS POLICY FORM CERTIFICATIONS, Multi-Use Form," which also is to be utilized for filing certifications for file-and-use under Article 3.42(c), as well as for corrections, resubmissions, substitutions, and filings for forms exempted from review and official action by these sections. Form "TEXAS POLICY FORM CERTIFICATIONS" is available from the Life/Health Group, has been filed with the Texas Register Division of the Secretary of State for public inspection, and is adopted by reference in these sections. The form also is reproduced in full as Figure 1 in §3.4020 of this title (Relating to Appendix).

(h) Copies of Previously Approved Forms Subsequently Submitted in Foreign Language (Non-English). Any form not otherwise exempted under these sections that is submitted in Braille as an exact copy of a previously approved form, or any form that has been translated into a foreign language from its previously approved English version, is exempt from the review and approval requirements of the Insurance Code Article 3.42. Such forms must be filed in accordance with and accompanied by the required certification as prescribed in Subchapter A of this chapter. The certification form required to be used in filing the certification is the same as that described in subsection (g) of this section.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 20, 1999.

TRD-9908892
Lynda Nesenholtz
General Counsel and Chief Clerk
Texas Department of Insurance
Effective date: January 9, 2000
Proposal publication date: October 15, 1999
For further information, please call: (512) 463-6327

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Chapter 7. CORPORATE AND FINANCIAL REGULATION

Subchapter J. EXAMINATION EXPENSES AND ASSESSMENTS

28 TAC §7.1012

The commissioner of insurance adopts an amendment to §7.1012 concerning assessments to cover the expenses of examining insurance companies. The amendment is adopted without changes to the text as proposed in the November 12, 1999, issue of the Texas Register (24 TexReg 9944).

The amendment is necessary to provide a rate of assessment for domestic and foreign insurance company examination expenses in 2000 which will provide the revenue necessary to fund the appropriations made by the Legislature.

Section 7.1012 provides the method and rates of assessment for examination expenses of foreign and domestic insurance companies. Rates of assessment are levied against and collected from each domestic insurance company based on admitted assets and gross premium receipts for the 1999 calendar year, and from each foreign insurance company examined during the calendar year 2000 based on a percentage of the gross salary paid to an examiner for each month or part of a month during which the examination is made. The department anticipates that the adopted rate will produce revenue of $12,147,056 to the state's general revenue fund. The expenses and charges to be assessed are in addition to, and not in lieu of, any other charge which may be made under the law, including the Insurance Code, Article 1.16.

No comments were received regarding adoption of the amendment.

The amendment is adopted under the Insurance Code, Article 1.16 and §36.001 (formerly Article 1.03A). The Insurance Code, Article 1.16(a) and (b) authorizes the commissioner of insurance to make assessments necessary to cover the expenses of examining insurance companies and to comply with the provisions of the Insurance Code, Articles 1.16, 1.17, and 1.18, in such amounts as the commissioner certifies to be just and reasonable. In addition, Article 1.16(c) provides that expenses incurred in the examination of foreign insurers by Texas examiners shall be collected by the commissioner by assessment. Section 36.001 (formerly Article 1.03A) authorizes the commissioner of insurance to adopt rules and regulations for the conduct and execution of the duties and functions of the department only as authorized by statute.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 20, 1999.

TRD-9908907
Lynda Nesenholtz
General Counsel and Chief Clerk
Texas Department of Insurance
Effective date: January 9, 2000
Proposal publication date: November 12, 1999
For further information, please call: (512) 463-6327

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TITLE 30. ENVIRONMENTAL QUALITY

Part 1. TEXAS NATURAL RESOURCE CONSERVATION COMMISSION

Chapter 101. GENERAL AIR QUALITY RULES

Subchapter H. EMISSIONS BANKING AND TRADING

Division 2. EMISSIONS BANKING AND TRADING OF ALLOWANCES

30 TAC §§101.330-101.337

The Texas Natural Resource Conservation Commission (TNRCC or commission) adopts new §101.330, Definitions; §101.331, Applicability; §101.332, General Provisions; §101.333, Allocation of Allowances; §101.334, Allowance

Deductions; §101.335, Allowance Banking and Trading; §101.336, Emission Monitoring, Compliance Demonstration, and Reporting; and §101.337, El Paso Region. The sections are adopted with changes to the proposed text as published in the September 10, 1999 issue of the *Texas Register* (24 TexReg 7137). The adopted rules will also be submitted as a proposed revision to the state implementation plan (SIP).

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

Senate Bill 7 (SB 7), 76th Legislature, 1999, amended the Texas Utilities Code (TUC), Title 2, Public Utility Regulatory Act, Subtitle B, Electric Utilities, and created a new Chapter 39, Restructuring of Electric Utility Industry. SB 7 requires the commission to implement the permitting and allowance requirements of new TUC, §39.264, concerning Emissions Reductions of "Grandfathered Facilities." TUC, §39.264 requires the commission to develop a mass cap and trade system to distribute emission allowances for use by grandfathered and electing electric generating facilities (EGF). Under TUC, §39.264, two categories of EGFs are eligible to use the adopted trading system. The first category consists of EGFs in existence on January 1, 1999, which were not subject to the requirement to obtain a permit under Texas Clean Air Act (TCAA), §382.0518(g). These facilities are referred to as "grandfathered" facilities. The second category of EGFs consists of permitted EGFs that are not subject to the permitting requirements of TUC, §39.264, yet elect to participate in the allowance trading system. These facilities are referred to as "electing" EGFs. TUC, §39.264 also requires that grandfathered EGFs apply for a permit on or before September 1, 2000, and obtain a permit by or cease operation after May 1, 2003.

These new sections are adopted concurrently with new sections in 30 TAC Chapter 116, concerning Control of Air Pollution by Permits for New Construction or Modification. The new Chapter 116, Subchapter I, concerning Electric Generating Facility Permits, contains the requirements for permitting of grandfathered and electing EGFs. The adopted amendments to Chapter 116 are published in this issue of the *Texas Register*.

TUC, §39.264(g) and (h) requires the commission to allocate emission allowances to grandfathered EGFs in defined regions of the state. As stated in TUC, §39.264(c), the Legislature intended that total annual emissions of nitrogen oxides (NO_x) from grandfathered EGFs would not exceed 50% of the emissions during 1997 as reported to the commission, and additionally for coal-fired grandfathered EGFs, total annual emissions of sulfur dioxide (SO_2) would not exceed 75% of the emissions during 1997 as reported to the commission. To further this goal, TUC, §39.264(h) provided emission rates to calculate specific allowances.

TUC, §39.264(c) allows emission limitations to be met through an emissions allocation and allowance transfer system. An allowance trading program is a regulatory program which caps emissions over a designated region to a level consistent with regulatory goals. Each grandfathered and electing EGF must hold allowances equal to or greater than its emissions to be in compliance with the program. For example, if a grandfathered EGF's emissions are 100 tons over the control period, the compliance account for this grandfathered EGF should reflect a balance equal to or greater than 100 tons of allowances. The program encourages EGFs to determine the methods of control which will allow the EGF to meet its allowances. Further, the program allows for trading of allowances between grandfathered and electing EGFs in the same region, thereby creating alternatives for control. For example, if a grandfathered EGF emitted 100 tons over the control period and has a balance of 150 allowances in its compliance account, the grandfathered EGF may sell the unused portion–50 tons of allowances–to another grandfathered or electing EGF. This trading provision allows companies to determine the most economical method of meeting the regulation, either by purchasing surplus allowances created by another grandfathered or electing EGF's reductions, or by making their own reductions.

Consistent with TUC, §39.264(i), EGFs currently permitted under 30 TAC Chapter 116, Subchapter B, concerning New Source Review Permits, may elect to participate in the permitting program adopted concurrently in Chapter 116, Subchapter I. These permitted facilities electing to participate in the permitting program under Chapter 116, Subchapter I are called "electing" EGFs. In the concurrently adopted amendments to Chapter 116, the existing New Source Review (NSR) permit will be altered to include a reference to a permit issued under Chapter 116, Subchapter I. Participation in the permitting program will allow electing EGFs to obtain allowances under the emissions banking and trading of allowances (EBTA) program. It may be advantageous for a company to include all EGFs, regardless of permitting status, in the permitting program to allow maximum flexibility in control strategies. Under TUC, §39.264(i)(2) and (4), electing EGFs are given allowances equal to their actual emissions reported in the 1997 Emissions Scorecard from EPA's Acid Rain Program unless a federal or state standard otherwise limits the emission rate.

SECTION BY SECTION DESCRIPTION

The new §101.330 contains the definitions to be used in the EBTA. "Allowance" means the authorization to emit one ton of NO_x or SO_2 during the specified control period or any specified control period thereafter. "Authorized account representative" is the responsible person who is authorized, in writing, to transfer and otherwise manage allowances. "Banked allowance" is an allowance which is not used to reconcile emissions in the designated year of allocation, but which is carried forward into next year and noted in the compliance or broker account as "banked." In response to public comment, a new definition of "Broker" was added to §101.330(4). "Broker" means a person who opens an account and participates in the EBTA for the purposes of banking and trading emissions allowances and not to satisfy emission requirements of an EGF. "Broker account" means the account where allowances held by a broker are recorded. Allowances held in a broker account may not be used to satisfy compliance requirements for these rules. Grandfathered and electing EGFs can purchase allowances from brokers; however, the allowances are not eligible to meet reduction requirements until the ownership of the allowances has been transferred and the allowances reside in the purchaser's compliance account. The definition of "Coal" was added to §101.330(6) to clarify any references to coal-fired EGFs. "Coal" means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388 92 ''Standard Classification of Coals by Rank'' (as incorporated by reference in Title 40 Code of Federal Regulations (CFR), §72.13 (effective June 25, 1999)). The definition of "Coal-fired" was added to §101.330(7) to clarify any references to coal-fired EGFs. "Coal-fired" means the combustion of fuel consisting of coal or any coal-derived fuel (except coal-derived gaseous fuels with a sulfur content no greater than natural gas), alone or in combination with any other fuel. The definition is independent of the percentage of coal or coal-derived fuel consumed during any control period. "Compliance account" means the account for a grandfathered or electing EGF or for multiple grandfathered or electing EGFs in which allowances are held. An EGF not under common control or ownership may have separate compliance accounts for the purpose of meeting the requirements of the EBTA and Chapter 116, Subchapter I. "Control period" means the 12-month period beginning May 1 of each year and ending April 30 of the following year, which is consistent with TUC, §39.264(c). Control periods will begin May 1, 2003. "East Texas Region" means all counties traversed by or east of Interstate Highway 35 (IH-35) north of San Antonio, or traversed by or east of Interstate Highway 37 (IH-37) south of San Antonio, and also including Bexar, Bosque, Coryell, Hood, Parker, Somerville, and Wise Counties. The commission has modified the definition of "East Texas Region" from TUC, §39.264(g) to clarify that counties east of IH-35 and west of IH-37 are not included in this region. The commission believes that had the Legislature intended for the definition to include these counties, the definition would have simply referenced IH-35 and not IH-37 also. Additionally, these counties (between IH-35 and IH-37) have been excluded from commission plans involving statewide air control strategies, and the commission believes that the Legislature was attempting to be consistent with current commission planning structures. "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. "Electing electric generating facility" is an EGF that is not subject to the requirements of TUC, §39.264, that elects to comply with Chapter 116, Subchapter I. The definition of "El Paso Region" was revised in response to comments, and the basis for this revision is discussed in the ANALYSIS OF TESTIMONY portion of this preamble. The "El Paso Region" is now defined to include all of El Paso County, Ciudad Juarez, Mexico, and Sunland Park, New Mexico. The definition for "Grandfathered electric generating facility" was added to §101.330(14) to clarify any references to "grandfathered" EGFs. "Grandfathered electric generating facility" means a facility that is not subject to the requirements to obtain a permit under TCAA, §382.0518(g) and 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. The commission originally modified this definition to exclude a facility that generates electric energy primarily for internal use, but during 1997 sold to a utility power distribution system less than one-third of its potential electrical output capacity. This exclusion eliminates cogeneration facilities that were not intended to be included in this program. This portion of the definition regarding cogeneration facilities was removed and placed under §101.331(b), regarding Applicability. The exemption was modified to also exclude EGFs that sold less than 219,000 megawatt hours to a utility power distribution system. This reference was added to exempt small cogenerators who may exceed the one-third limitation. This is more consistent with the Acid Rain Program exemption for affected units. "Heat input" is the heat derived from the combustion of any fuel at an EGF. Heat input does not include the heat derived from reheated combustion air, recirculated flue gas, or exhaust from other sources. The definition of "NO_x" was revised in response to comments. "NO_x allowance" is an authorization to emit NO_x, valid only for the purposes for meeting the requirements of this division and Chapter 116, Subchapter I. The definition of "Permitted electric generating facility" was removed from §101.330. The term "permitted" was unclear as used in the proposed rule as to whether "permitting" was referencing a permit under Chapter 116, Subchapter B, Subchapter H, or Subchapter I. The rules were changed to specifically identify the type of permit being referenced. The definition of "Person" was added to §101.330(17) in response to comments. "Person" for the purpose of initial issuance of permits under Chapter 116, Subchapter I, and for the issuance of allowances under these rules, includes an individual, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, and a corporation, but does not include an electric cooperative. "SO_2 allowance" is an authorization to emit SO_2, valid only for the purposes for meeting the requirements of these rules and Chapter 116, Subchapter I. "West Texas Region" means all counties not contained in the East Texas or El Paso Regions.

The new §101.331 establishes the applicability of banking and trading allowances. EGFs subject to the concurrently adopted Chapter 116, Subchapter I or electing EGFs would be required to comply with EBTA. The section also allows the opening of broker accounts for those not required to participate in the EBTA. Since §101.330(4) now includes the definition of "Broker," this section was revised to refer to "brokers."

The new §101.332 contains the general provisions for the EBTA. Compliance with the allowance system would begin with the control period beginning May 1, 2003. Allowances would only be valid for meeting the purposes of the EBTA, and cannot be used to meet or exceed the limitations of any permit or applicable law, generate emission reduction credits, or satisfy emission offset requirements under federal NSR. Because allowances do not by themselves meet federal criteria as creditable emission reductions, they may not be used to satisfy other requirements of the Federal Clean Air Act (FCAA), such as netting for Prevention of Significant Deterioration (PSD), NSR, or offsets under a nonattainment NSR permit. Neither a NO_x allowance nor an SO_2 allowance constitutes a security or property right. To meet the requirements of TUC, §39.264(e), this section requires that on June 1 of each year, beginning in 2004, an EGF shall hold in its compliance account a quantity of allowances that is equal to or greater than the total emissions of that air contaminant emitted during the prior control period. The original proposal required that the quantity of allowances should be in place by May 1; however, this was in response to comments to allow a 30-day reconciliation period. The commission requires that allowances be allocated, transferred, or used as whole allowances. For simplicity, the number of allowances will be rounded down for decimals less than 0.50 and rounded up for decimals of 0.50 or greater. This section also allows only one compliance account for use by multiple permitted EGFs located at the same property and under common ownership or control. These limitations on the number of compliance accounts will assist the commission in the allocation of allowances and tracking of allowance transfers. Section 101.332(i), which incorporated TUC, §39.264(n), concerning the deduction of allowances from compliance accounts where the EGF exceeded its allowances, was moved to §101.333(4) for organizational clarity.

The new §101.333(1) and (2) contains the methods by which allowances for grandfathered and electing EGFs are calculated. As specified in TUC, §39.264(h), the allowances will be calculated by multiplying total heat input measured in millions of

British thermal units (MMBtu) during 1997 by an emission rate expressed in pounds/MMBtu divided by 2,000. To determine allowances, the commission will use information obtained from the United States Environmental Protection Agency's (EPA) 1997 Acid Rain Program's Emissions Scorecard. This scorecard is the only readily-available, consistently-reported, and comprehensive source of 1997 heat input data for EGFs. This was the basis for determining the emission rates necessary to achieve the program's goals of a 50% reduction in NO_x emissions, and for coal-fired EGFs, 25% reduction in SO_2 emissions from 1997 levels. If information for an EGF concerning heat input is not reported to the acid rain scorecard, the executive director may approve a method for calculating heat input for that EGF as long the method is consistent with the requirements of the acid rain scorecard. Paragraphs (1) and (2) also specify the emission rates for the El Paso, East Texas, and West Texas Regions. In the East Texas Region, the emission rate is 0.14 pounds of NO_x per MMBtu and 1.38 pounds of SO_2 per MMBtu. The emission rate in the West Texas and El Paso Regions is 0.195 pounds of NO_x per MMBtu. Consistent with TUC, §39.264(i)(2), the allowances for electing EGFs are equal to the EGF's emission in tons in 1997. Should a coal-fired EGF permitted under Chapter 116, Subchapter B, elect to participate in the permitting program under Chapter 116, Subchapter I, the annual emissions of SO_2 from 1997 would be used to establish its allowances.

In addition to the 50% reduction expected from grandfathered EGFs under TUC, §39.264, the commission anticipates adopting additional requirements for EGFs in nonattainment areas to meet the ozone National Ambient Air Quality Standard (NAAQS). For each nonattainment area, the amount of reductions for the SIP will be consistent with the SIP modeling efforts for that area. At this time, the point source reductions expected in the Dallas/Fort Worth (DFW) area are 88%. Reductions in the Beaumont/Port Arthur (BPA) area are expected to be 40-50%, and reductions in the Houston/Galveston (HGA) area are expected to be 90%. The commission expects to propose the reductions for BPA and DFW areas in December of 1999. For the HGA area, proposal is expected in May of 2000. The commission expects to propose reductions in attainment counties of east and central Texas not later than December of 1999. Future rulemaking addressing these reductions may affect the EBTA and the allocation of future allowances. TUC, §39.264(s) recognizes the current authority of the commission to require additional reductions of NO_x or SO_2, and as future SIP rules are developed allowances may be reduced accordingly. The new §101.333(3) incorporates this authority. The new §101.333(4), concerning the deduction of allowances from compliance accounts where the EGF exceeded its allowances, was added to incorporate the requirements of TUC, §39.264(n). Paragraph (4) was moved from §101.332(i) for organizational clarity.

The commission must allocate allowances for grandfathered EGFs by January 1, 2000, as required by TUC, §39.264(h). In order to meet this deadline, the commission will issue an order prior to January 1, 2000 to allocate these allowances. The list entitled "Nitrogen Oxide and Sulfur Dioxide Allowances for Grandfathered Electric Generating Facilities" is available from the commission on request and is available on the commission's Web Site. To meet the statutory deadline to issue allowances by January 1, 2000, the new §101.333(5) provides that a commission order will be issued by that date with the allowances for grandfathered EGFs. The allowances allocated for subsequent years will reflect the same values issued in the initial allocation.

Initial allowances for electing EGFs for the control period beginning May 1, 2003 will be allocated by January 1, 2001. Since the commission will not know which EGFs are electing to participate in the permitting program until September 1, 2000, it would be impossible to allocate allowances for electing EGFs on the same schedule as the grandfathered allocations. This later allocation schedule will allow companies to determine whether to participate in the programs and which programs best suit their individual business needs. The new §101.333(5)(A)(ii), formerly §101.333(4)(A)(ii), requires allocation of allowances for electing EGFs by January 1, 2001. This section was revised to include municipal corporations, electric cooperatives, and river authorities that choose to obtain a permit under Chapter 116, Subchapter I for EGFs that were previously exempted under 30 TAC §116.910(d) from the permitting program. These EGFs will also be allocated allowances by January 1, 2001.

To allow EGFs to identify potential sellers of allowances, the commission shall maintain a publicly available registry of the allowances in each compliance account as provided in the new §101.333(7). For each transfer, the registry shall include the price paid per allowance. The registry shall not contain proprietary information. The commission believes that public access to information regarding the price and transfer of allowances will promote an open trading system.

In response to comments, the new §101.334 was renamed "Allowance Deductions" and modified extensively from the proposal. The section now addresses only the deduction of allowances from compliance accounts. The section specifies the method or equations that will be used to determine the amount of allowances to be deducted at the end of each control period from compliance accounts in three circumstances: (1) for electing EGFs whose heat input for the control period is equal to or greater than its heat input for 1997, for all grandfathered EGFs, and electing EGFs whose heat input for the control period is less than its heat input for 1997 where the reduced utilization or shutdown has been replaced by another EGF permitted under Chapter 116, Subchapter I. This formula allows any surplus allowances not used by grandfathered EGFs and any surplus allowances not created by reduced utilization or shutdowns from electing EGFs to be banked or traded; (2) for electing EGFs if the heat input for the control period was less than the heat input for 1997 and whose reduced utilization or shutdown has not been replaced by another EGF. The formula ensures that surplus allowances resulting from reduced utilization or shutdowns from these electing EGFs cannot be banked or transferred, as provided in TUC, §39.264(i)(3); and (3) for electing EGFs whose heat input for the control period was less than the heat input for 1997, whose reduced utilization or shutdown has been replaced by another EGF, and for EGFs not permitted under Chapter 116, Subchapter I. This formula allows surplus allowances to be banked or traded if they were generated from reduced utilization or shutdown and the EGF can document that the reduced utilization or shutdown has been replaced by another EGF. The requirements concerning the trading of allowances have been moved to a new §101.335.

The new §101.335, Allowance Banking and Trading, contains the general requirements for banking and trading of allowances. The requirements in this section are necessary to ensure consistency with TUC, §39.264(j). The new §101.335(a) specifies that allowances may only be used for the current or subsequent control period for which they were allocated. Any surplus allowances not used during a control period may be banked for use in subsequent control periods. Allowances may only be used within the same region. The new §101.335(b) specifies that allowances may be traded at any time during a control period by authorized account representatives. Notification of trades must be made to the commission within 30 days of the trade. The new §101.335(c) specifies that trades are prohibited prior to May 1, 2003. The new §101.335(d) specifies that traded allowances held in compliance accounts must have originated from EGFs in the same region, and the new §101.335(e) specifies that allowances held in broker accounts may only be transferred to compliance accounts for EGFs located in the region where the allowances were originally allocated.

Section 39.264 allows EGFs the flexibility to decide when and where to make reductions or to add on controls. EGFs should consider local impacts of allowance trades specifically on those counties which are nonattainment and near-nonattainment. For example, most near-nonattainment areas have EGFs that are in close proximity to these areas. These EGFs emit significant amounts of NO_x, which has been shown to heavily influence local ozone levels. Other EGFs located a greater distance from these areas have regional impacts on background ozone levels, but do not impact near-nonattainment areas to the extent the closer facilities can.

While the commission believes that the trading program will result in emission reductions throughout the East Texas Region, emission reductions, rather than allowance trades, at the nearby EGFs should be thoroughly considered before investments are made for emission control equipment at more distant plants. In making these economic decisions, it is incumbent on businesses to weigh the environmental consequences of their actions. Prior to making an allowance trade to a nonattainment or near-nonattainment area, EGFs must be aware that such trades might jeopardize the status of a near-nonattainment area. For example, at this time the Tyler/Longview/Marshall area is operating under the terms of a flexible attainment region (FAR). If numerous trades occur into that area, the conditions of the FAR may be compromised. The FAR will expire in September 2001 and can be extended by the parties. During the term of the FAR agreement, EPA will treat the area under an approach similar to a maintenance plan area. However, EPA may designate the area as nonattainment, regardless of whether a FAR agreement is in place. Designation of nonattainment could result in additional reductions of NO_x from EGFs in the Northeast Texas FAR area. Furthermore, a nonattainment designation would require additional reductions from industry sources and potential restrictions on trade into the new nonattainment area. The commission encourages EGFs to consider the long-term consequences of decisions to utilize allowances rather than the installation of controls at EGFs located close to nonattainment areas and in near-nonattainment areas.

The new §101.336 establishes compliance demonstration methods. All grandfathered and electing EGFs using the EBTA must comply with 30 TAC §116.914, Emissions Monitoring and Reporting Requirements. By June 30 of each year, grandfathered and electing EGFs participating in the EBTA shall report to the commission the amount of emissions of each allocated air contaminant during the preceding control period. The new §101.336(b) requires that at the end of each control period, the owner or operator of a grandfathered or electing EGF to report its emissions to balance the emissions with the allowances in its compliance account.

The new §101.337 will allow grandfathered or electing EGFs in the El Paso Region to meet emission allowances using credits from the City of Juarez, in the United States of Mexico and from EGFs located in Sunland Park, New Mexico. The reduction must be reviewed and approved by the executive director and must be surplus, permanent, quantifiable, enforceable by the commission, and not required by other rule or law. Under TUC, §39.264(q), §101.337 would also exempt the El Paso Region from the EBTA if either the EPA or the commission determines that reductions of NO_x will increase ambient levels of ozone. Currently, NO_x reductions are not required for facilities in the El Paso nonattainment area because EPA has granted a waiver under FCAA, §182(f), concerning NO_x Requirements. Under this waiver, NO_x reductions are not required if the attainment demonstration for compliance with the ozone NAAQS can be made without a NO_x control strategy. The basis for this waiver does not satisfy TUC, §39.264(q) because it has not been demonstrated, under the §182(f) waiver or otherwise, that NO_x reductions would increase ambient ozone in El Paso County. The EGFs in the El Paso Region would still be required to obtain a permit under Chapter 116, Subchapter I regardless of the determination that NO_x reductions are counterproductive in controlling ambient ozone levels in the El Paso Region. The commission believes that this requirement is appropriate since TUC, §39.264(e) provides that EGFs without a permit may not operate after May 1, 2003, and TUC, §39.264(q) refers only to reduction requirements, not permitting requirements.

FINAL REGULATORY IMPACT ANALYSIS

The commission has reviewed the adopted rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and has determined that the rulemaking is not subject to §2001.0225 because it does not meet the definition of a "major environmental rule" as defined in that statute. "Major environmental rule" means a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. Because the specific intent of the adoption is procedural in nature and specifies how and when emission allowances can be banked and traded; makes the trading and/or banking of emission allowances voluntary; and allows the EGFs the flexibility to decide the extent of banking and trading of allowances, the rulemaking does not meet the definition of a "major environmental rule." The adopted sections only apply to grandfathered EGFs and electing EGFs. Finally, the adopted sections do not meet any of the four applicability requirements of a "major environmental rule." The adopted sections do not exceed a standard set by federal law, exceed an express requirement of state law, or exceed a requirement of a delegation agreement. In addition, the sections are adopted specifically to implement the requirements of TUC, §39.264.

TAKINGS IMPACT ASSESSMENT

The commission has prepared a takings impact analysis under Texas Government Code, 2007.043.The following is a summary of that analysis. While these amendments may result in capital costs for some EGFs, the amendments do not affect private property in a manner that restricts or limits an owner's right to the property that would otherwise exist in the absence of the governmental action. Consequently, this adoption does not meet the definition of a takings under Texas Government Code, §2007.002(5). These new sections implement the requirements of TUC, §39.264. EGFs are required to reduce emissions of NO_x by 50% and, if applicable, SO_2, by 25%. Although EGFs are required to make specific emission reductions, these facilities have alternatives available under the banking program that may allow the EGF to avoid installing add-on controls. Further, allowances can be transferred under the banking program so that EGFs have opportunities to buy and sell allowances in order to respond to business needs. This action is intended to reduce emissions of NO_x and SO_2. The action significantly advances this purpose by requiring substantial reductions in the emission of NO_x and SO_2 through a system of emission allowances. While requiring these reductions, these rules allow the trading of emission allowances so that EGFs may transfer allowances providing flexibility for compliance with emission limits. This action is taken in response to a real and substantial threat to public health and safety and significantly advances the health and safety purpose and imposes no greater burden than is necessary to achieve the health and safety purpose.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

The commission has determined that this rulemaking relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission's rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with Texas Coastal Management Program. As required by 31 TAC §505.11(b)(2) and 30 TAC §281.45(a)(3), relating to actions and rules subject to the CMP, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission has reviewed this action for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council. For the adopted sections relating to the authorization of emission allowances and the banking and trading of allowances, the commission has determined that the rules are consistent with the applicable CMP goal expressed in 31 TAC §501.12(1) of protecting and preserving the quality and values of coastal natural resource areas, and the policy in 31 TAC §501.14(q), which requires that the commission protect air quality in coastal areas. This adoption is intended to reduce overall emissions of NO_x and SO_2 from EGFs. This action is consistent with 40 CFR because it does not authorize an emission rate in excess of that specified by federal requirements.

PUBLIC HEARINGS AND COMMENTERS

The commission conducted public hearings concerning this adoption in El Paso and Lubbock on October 1, 1999, in Austin on October 4, in Irving on October 5, in Houston on October 7, and in Beaumont on October 7.

The following commenters submitted written comments or provided testimony during the public comment period which closed on October 11, 1999: EPA-Acid Rain Division (EPA-ARD); EPA-Clean Air Markets Division (EPA-CAMD); EPA-Air Permits Division (EPA-APD); EPA-Air Planning Section (EPA-APS); University of Texas System, Office of General Counsel (UT); Enron, Central and South West Services, Inc. (CSW); TXU Business Services (TXU); Brazos Electric Power Cooperative, Inc. (Brazos); Baker & Botts, L.L.P.-Texas Industry Project (Baker & Botts); Clark & Seay, L.L.C. (Clark & Seay); Southwestern Public Service Company (SPS); Entergy Gulf States, Inc./Entergy Texas (Entergy); El Paso Electric Company (EPE); Lloyd, Gosselink, Blevins, Rochelle, Baldwin & Townsend, P.C.-City of Garland (Lloyd Gosselink); League of Women Voters of Texas (LWV-TX); The Center for Energy and Economic Development (CEED); Association of Electric Companies of Texas, Inc. (AECT); Reliant Energy (Reliant); Entergy Services Inc. (Entergy Services); Environmental Defense Fund (EDF); City of Austin/Austin Energy (AE); Sustainable Energy and Economic Development Coalition (SEED); Public Citizen, Texas Clean Water Action, and Texas Communities Project (PC); City Public Service of San Antonio (CPS); Sierra Club (Sierra); Bracewell & Patterson (B&P); Lubbock Power & Light & Water (LP&L); Clark, Thomas & Winters (CT&W); Central & South West Services, City of Austin, City Public Service, El Paso Electric, Entergy, Reliant Energy, Southwestern Public Service, and TXU (Group A); Mothers for Clean Air (MCA); Neighbors for Neighbors (NFN); the Honorable Lon Burnam, State Representative, District 90; and 17 individuals.

ANALYSIS OF TESTIMONY

One individual commented that the commission should exercise its authority to require significant reductions at power plants in East Texas, while another individual added that the reductions should be permanent. Three individuals stated that the commission should enforce reduced emissions from grandfathered electric generating facilities, and two more individuals added that the commission should be as strict as possible in that enforcement.

While this adoption addresses grandfathered EGFs only, the commission is developing rules that will apply NO_x restrictions on all EGFs in the East Texas Region. The specific level of emissions required from these facilities will be determined on computer analysis that indicates what reductions should be required to assist the affected nonattainment areas in meeting the NAAQS. The net reductions required under this adoption are permanent. The commission will exercise its full enforcement power as authorized by statute, rule, or as governed by enforcement policy.

Four individuals stated that the commission should seek improvements that address SO_2, particularly to improve visibility in Big Bend. Another individual added that the commission must require a larger NO_x and SO_2 reduction to reduce acid rain and ozone in Texas nonattainment areas.

In cooperation with EPA and the National Park Service, the commission is analyzing the nature and location of required reductions to address reduced visibility in Big Bend National Park. This analysis is incomplete and therefore, the commission believes that requiring reductions specifically for their effect on the Big Bend area prior to the completion of this analysis is premature. The authority granted to the commission under TUC, §39.264 and other existing authority allows the commission to seek additional reductions in SO_2 as needed. As stated previously, the commission is addressing additional NO_x reductions that may be required to assist attainment of the NAAQS in a separate rulemaking. There are no areas in Texas that are nonattainment for SO_2, and the commission is not aware of any areas that are adversely affected by acid rain.

One individual stated that the commission should not allow a cap and trade or banking system because it avoids environmental justice issues and perpetuates emissions in low-income areas. The same individual suggested that the exclusion for individual units to be regulated under TUC, §39.264 be lowered to ten megawatts from 25 megawatts. This individual also stated that the commission estimate of cost of compliance with the requirements of the adoption is low, and it appears that the commission is allowing low-grade technology to be applied to the regulated units.

The trading and banking provisions of this adoption are required elements of the reduction program under TUC, §39.264. SB 7 provides that total annual emissions of NO_x from grandfathered EGFs will not exceed 50% of the NO_x emissions in 1997 as reported to the commission and that for coal-fired grandfathered EGFs, the total annual emissions of SO_2 will not exceed 75% of the emissions during 1997, as reported to the commission. SB 7 also provides that the trades of allowances will only occur within the same region, either East Texas, West Texas, or El Paso. The effect of this will be an overall 50% reduction in NO_x and a 25% reduction in SO_2 within the region. SB 7 does not require a specific level of reduction at any individual grandfathered EGF. The exemption level for individual generating units of 25 megawatts is specified in TUC, §39.264(d). As discussed elsewhere in the adoption preamble, the commission has also excluded EGFs that generate power primarily for internal use, but that during 1997 sold one-third of their generated power or less than 219,000 megawatt-hours to the utility power distribution system. The commission believes that excluding these EGFs is consistent with SB 7 and will not negatively affect the overall emission reductions required by the program. Lowering the exemption to ten megawatts will require small generators to participate in the EBTA and permitting program and will achieve little environmental benefit in relation to the cost of compliance with the program. The commission has based its estimate of the cost of applying control technology to attain the 0.14 pounds/MMBtu on the February 1999 joint Public Utility Commission of Texas (PUCT) and TNRCC report, *Electric Restructuring and Air Quality: A Preliminary Analysis of Reductions and Costs of Nitrogen Oxides Controls from Electric Utility Boilers in Texas.* The estimate does not limit the amount EGFs must spend to meet the EBTA and accounts for technology of necessary sophistication to meet the requirements of this adoption.

The Honorable Lon Burnam, State Representative, District 90, commented concerning the implementation of SB 7 and its impact on consumers from an economic perspective. Mr. Burnam expressed his concerns that the commission implement the provisions of SB 7 free from the influence of lobbyists. Mr. Burnam urged the commission to consider public health in the process of implementing SB 7.

The provisions of SB 7 concerning deregulation of the electric industry will be implemented by the PUCT. The commission conducted six hearings in order to seek the public comment of citizens, the regulated community, and environmental groups. The hearings were conducted in El Paso, Lubbock, Austin, Irving, Houston, and Beaumont. Prior to proposal, the commission held a stakeholder meeting to seek input from interested persons. Notice of this meeting was provided on the commission's web page. In addition, pre-proposal drafts of the rules were posted on the commissions's web page with a request for comments. The commission believes that the adopted rules are consistent with SB 7 and remains committed to implement the program in a fair and impartial manner. Since EGFs are being permitted under the requirements of TUC, §39.264, which does not require a health effects review, no review is included in this adoption. The commission believes that this program will reduce ambient levels of NO_x and SO_2 and improve the overall air quality of the state. These reductions will assist the commission in its efforts to attain the health-based NAAQS.

Clark & Seay and MCA commented that all power plants that are in or near an area with unsafe air should be required to meet the 0.14 pounds/MMBtu standard used in federal laws and to the level to which all grandfathered plants will be required to be cleaned up. In addition, LWV-TX commented that the rules in general should be expanded to require that all power plants in areas with unsafe air or that contribute to those nonattainment areas meet the same standard.

This adoption implements the requirements of TUC, §39.264 and application of this statute is limited to grandfathered EGFs and those EGFs that elect to participate in the permitting and trading program. The intent of SB 7 is not to achieve attainment with the NAAQS, but to permit and reduce emissions from grandfathered EGFs. While the implementation of SB 7 will provide emission reductions in areas near grandfathered EGFs, the commission recognizes that it will likely be necessary to adopt rules that will require air pollution control in attainment areas as well as additional rules for nonattainment areas. These controls would not only apply to emissions of NO_x from grandfathered EGFs, but permitted EGFs and other sources of NO_x as well. In addition, the commission will establish emission rates that it has determined are necessary to meet air quality standards. Rules implementing these additional controls are scheduled for proposal in late 1999 or early 2000. The commission is not aware of any federal standards that require EGFs to meet a NO_x emission restriction of 0.14 pounds/MMBtu.

EDF commented that TUC, §39.264(n)(1) includes two specific penalties for facilities that exceed their allowances. The commenters noted that the proposed rules did not include any administrative penalties, and recommended that they be added at a level sufficient to deter noncompliance. EDF recommended three times the current market value of allowances.

The commission does not typically address the amount of administrative penalties in specific rules. Rather, penalty amounts are established in accordance with the commission's penalty policy. All enforcement cases not referred to the Office of the Attorney General go through staff preparation of an administrative penalty recommendation in accordance with the commission's penalty policy. Staff obtains an agreement or litigates to obtain an order against the respondent that requires the payment of penalties. The commission determines the amount of the penalty in accordance with the commission's enforcement rules and penalty guidance. The statutory language requires "enforcing an administrative penalty" and not "assessing" an administrative penalty.

Reliant requested that the published list of grandfathered EGFs should be revised by deleting the Cedar Bayou Units 1 and 2 (Account Number CI-0012-D) because the units are no longer grandfathered and are permitted under Permit Number 1532. In addition, Reliant provided heat input information for facilities that were missing from the proposed list. CPS commented that V.H.Unit 1 should be corrected from 2,946,936 MMBtu to 2,949,512 MMBtu, as was submitted to EPA in the Acid Rain Database.

The commission will make these corrections to the list entitled "Nitrogen Oxide and Sulfur Dioxide Allowances for Grandfathered Electric Generating Facilities" as requested.

EPE commented that the language in TUC, §39.102(c) and §39.264(i) illustrate EPE's exemption from Chapter 39 and EPE's ability to elect to designate a facility to become subject to §39.264, and the commenter noted that EPE is a "person" under TUC.

The commission agrees that EPE is a "person" under the TUC. The commission has not revised the rule to exempt EPE from the program requirements. TUC, Subchapter C, Retail Competition, §39.102, concerns retail customer choice, and exempts from TUC, Chapter 39, any electric utility that has a system-wide freeze for residential and commercial customers that is in effect from September 1, 1997 and extends beyond December 31, 2001, that has been found by a regulatory authority to be in the public interest. Subchapter C also contains §39.264, which requires any EGF that existed on January 1, 1999, that is not subject to the requirement to obtain a permit under TCAA, §382.0518(g), to apply for and obtain a permit from the commission.

Section 39.264 was added to SB 7 during the final weeks of the 76th Legislative Session. Its very specific intent is to require grandfathered EGFs to obtain a permit from the commission and to obtain reductions of NO_x and SO_2 in the regions as defined by the bill. TUC, §39.264 contains several specific references to the El Paso area that make it clear that the Legislature intended EGFs in that area to be subject to the permitting and allowance program. TUC, §39.264(g) requires the commission to develop rules that define the "El Paso Region." TUC, §39.264(h) specifies an emission rate for the El Paso Region. TUC, §39.264(p) specifically requires the commission to develop rules to allow EGFs in the El Paso Region to meet emissions allowances by using credits from reductions made in Ciudad Juarez, United States of Mexico. Finally, TUC, §39.264(q) allows the commission to exempt EGFs in the El Paso Region if the commission determines that reductions in NO_x would result in an increased amount of ambient ozone levels in El Paso County.

The Code Construction Act, §311.021, Texas Government Code, provides that "In enacting a statute, it is presumed that: (1) compliance with the constitutions of this state and the United States is intended; (2) the entire statute is intended to be effective; (3) a just and reasonable result is intended; (4) a result feasible of execution is intended; and (5) public interest is favored over any private interest." If TUC, §39.102 were read to exclude EGFs in the El Paso Region from the provisions of Chapter 39, the specific provisions of TUC, §39.264, concerning the El Paso Region, would be rendered ineffective. As prescribed by the Code Construction Act, the commission must interpret the provisions of Chapter 39 so that all sections can be given effect. To do otherwise would contravene the intent of the Legislature. Thus, the commission agrees the EPE is exempt from the provisions regarding customer choice in TUC, Chapter 39. However, if EPE were exempted from the permitting and EBTA requirements, the provisions of TUC, §39.264, concerning the El Paso Region, would be meaningless. The commission agrees that EPE may use the provisions of §116.912, concerning Electing EGFs.

Lloyd Gosselink commented that the rules do not address the use of oil as a backup fuel at a gas-fired facility. The commenter stated that under certain curtailment situations, gas may not be available, and gas-fired facilities may be required to switch to oil as a fuel source, and that under these conditions, facilities should not be penalized for any additional NO_x emissions.

The commission believes that a facility has the latitude to use any fuel as long as actual emissions comply with its allotted allowances, and the use is authorized by the appropriate NSR authorization. The commission does not believe it is appropriate to revise the rules to include an exception to exceed allowances in the case of a curtailment, because SB 7 does not allow for this exception. If a curtailment occurs, and emissions of NO_x exceed an EGF's allowances, the commission will rely on its enforcement policy to determine the appropriate response. Use of previously unused fuels may constitute a modification and require an NSR permit. The rules have not been revised in response to this comment.

LWV-TX commented that the TNRCC should restrict pollution trading in ways that assure significant reductions in air pollution.

SB 7 requires the commission to allocate allowances to grandfathered EGFs in defined regions of the state. The specific intent of SB 7 is that total annual emissions of NO_x from grandfathered EGFs will not exceed 50% of the NO_x emissions in 1997 as reported to the commission and that for coal-fired grandfathered EGFs, the total annual emissions of SO_2 will not exceed 75% of the emissions during 1997, as reported to the commission. The adopted rules provide the requirements for both the permitting of these grandfathered EGFs and an emission banking and trading program. Both of these programs are critical to the successful reduction of the NO_x and SO_2 emissions contemplated by SB 7. The EBTA contains restrictions on trading that will ensure that the regional emission reductions are enforceable. The commission believes the required reporting and monitoring, along with the statutorily defined enforcement provisions, will ensure that the program achieves the reductions intended by TUC, §39.264, and that no modification to the rule is necessary.

CEED commented that the preamble referenced adopting additional requirements for EGFs in nonattainment areas, indicating further reductions of 88% in DFW and 90% in HGA area. The commenter stated that the emissions inventory shows that these point sources only represent a minor source of NO_x emissions, since the majority of emissions are generated by on-road and off-road mobile and area sources, and that the inclusion of these statements regarding the further need to reduce emissions from EGFs continues to focus attention on sources which will not solve nonattainment problems in these areas. CEED also commented that the proposal preamble statements that EGFs must consider local impacts of allowance transfers and that "EGFs emit significant amounts of NO_x, which has been shown to heavily influence local ozone levels" are comments without any qualifications to specific EGFs and perpetuate the opinion by some that all EGFs emit significant levels of emissions. CPS also disagrees with the cited statements from the proposal preamble. CPS commented further that the mandatory SB 7 program was designed to be flexible, and allow reductions to be made in the most cost-effective manner, adding that the utility plants in San Antonio, owned by CPS, do not contribute heavily to local ozone levels, as indicated by previous modeling performed by the Alamo Area Council of Governments (AACOG) under the direction of the TNRCC. The commenter stated that TNRCC's concern that SB 7 allowance trading will jeopardize the regional strategy is unwarranted, at least for the near-nonattainment area of San Antonio. CPS also supports the removal of all references to SIP requirements from the SB 7 regulations.

The reductions mandated by SB 7 only apply to grandfathered EGFs in the defined regions of Texas. These reductions from grandfathered EGFs will be significant; however, it is unlikely that the reductions will be sufficient to address the need to further reduce emissions in both attainment and nonattainment areas. The commission believes that to achieve attainment with the NAAQS, it will be necessary to reduce emissions from all sources, both stationary and mobile, in both attainment and nonattainment areas. The reductions that will be achieved under the adopted rules will be significant towards reaching attainment. In addition, the commission believes that NO_x emissions from EGFs are not minor, but significantly contribute to ground-level ozone formation. The preamble comments regarding the potential impacts of trading on near-nonattainment areas were included to show the commission's recognition that emissions in near-nonattainment areas may have a negative effect on that area's ability to remain in attainment. Emission inventory information indicates that NO_x emissions from EGFs are approximately 47% of the stationary source NO_x emissions in the East Texas Region.

EPA-CAMD commented that in the proposed preamble, the cost-effectiveness numbers of $4,000 per ton of NO_x removed in the absence of emissions trading, or $2,000 per ton of NO_x removed with emissions trading, seem far too high. For example, in the May 25, 1999 Final Rule under §126 of the FCAA (64 FR 28300), EPA determined an average cost-effectiveness of $1,468 per ton of NO_x removed from electric generating units greater than 25 megawatts with emissions trading. Estimates for cost-effectiveness of NO_x control under the Ozone Transport Committee NO_x Budget Program range from $950-1,600 per ton. Furthermore, the commenter noted that some gas-fired units can achieve an average NO_x emission rate of 0.14 lb/MMBtu simply using combustion controls.

The commission supports the preamble language. The listed values were based on information developed for the joint Public Utility Commission of Texas (PUCT) and TNRCC report published in February 1999, entitled *Electric Restructuring and Air Quality: A Preliminary Analysis of Reductions and Costs of Nitrogen Oxides Controls From Electric Utility Boilers in Texas.* For simplicity in the report, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain generating units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of the Ozone Transport Assessment Group (OTAG) has analyzed market-based emission trading options, such as the EBTA, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. This analysis is applied to all utility generating units in the state, which may overstate the magnitude of the estimated compliance costs. The commission believes that, in practice, the costs of permitting and participation in the EBTA will be much less that what was estimated in the proposal.

EPA-APD commented on its understanding that the TNRCC will use the emission reductions which occur under these regulations to help demonstrate attainment and maintenance of NAAQS. The commenter further understood that the reductions will not be used for offsets and netting under NSR. With this understanding, EPA-APD supported the adoption of these regulations if the TNRCC adequately addresses the remaining comments.

The EBTA and electric generating facility permit (EGFP) programs will be submitted as a revision to the SIP. The resulting reductions will be used by the commission to further its attainment goals. Allowances cannot be used to satisfy emission offset requirements under federal NSR; thus, they will not be used as netting for PSD or for offsets under a nonattainment NSR permit.

PC recommended substituting renewable energy for electricity or energy used at a grandfathered facility, stating that this could provide a low-cost way to reduce emissions and result in the building of additional new clean energy sources. The commenter stated that concurrent rulemaking at the PUCT to implement the renewable portfolio standard in SB 7 has resulted in the development of capacity factors and other evaluation procedures that can be useful to the commission in converting renewable capacity to energy for purposes of calculating avoided emissions and providing for a periodic update for that factor. PC stated that these rules developed by the PUCT should be incorporated by reference into the commission's rules.

The purpose of this rulemaking is to obtain emissions reductions from EGFs based on the specific provisions of SB 7; in particular, the 50% NO_x reductions and the 25% SO_2 reductions, if applicable. These reductions are to be made based on certain emission rates set forth in TUC, §39.264(h). It is possible that a grandfathered or electing EGF could make reductions relying on the use of renewable energy and that the factors developed by the PUCT may be used to evaluate such a proposal. Since the commission can consider the rules of the PUCT among many sources of information to make such decisions, the commission does not believe it is necessary to incorporate the PUCT rules into Chapter 101 or Chapter 116. The commission agrees that using renewable energy to achieve emission reductions is a viable option and one that might result in cost savings to certain facilities. As the commission continues to develop the permitting and EBTA programs, issues concerning renewable energy can be considered. In addition, if a grandfathered or electing EGF substitutes renewable energy, the resulting emissions should be lower, requiring fewer allowances for compliance, thus creating an economic incentive.

PC believes that the proposed rules will fail to assure that emissions are actually reduced. PC believes that the utilities are unlikely to offer a reduction at any plant other than those that are oldest and used the least. Many of these plants are permitted as base-load plants which operate 60-80% of the time, but are kept only for peak use and are used infrequently, less than 20% of the year. Thus, a facility might be glad to modify its permit by reducing permitted emission that they would never really produce. PC recommends that the rules should be modified to require permit reductions based on the last five years of actual emissions.

The commission believes that the specified emission rates in the statute and the corresponding rules will achieve the target reductions. The intent of SB 7 is to achieve overall reductions of 50% NO_x emissions and 25% SO_2 emissions. An electing EGF would receive allowances equal to actual 1997 emissions, not permit allowable emissions, and would only be able to generate surplus allowances by reducing emissions below actual 1997 levels. Also, an electing EGF may not transfer or bank allowances that are conserved as a result of reduced utilization or shutdown unless the reduced utilization or shutdown results from the replacement of thermal energy from the electing EGF with thermal energy generated by any other EGF. Further, since SB 7 provides that 1997 is the base year for determining reductions, the commission does not believe it has the authority to require permit reductions based on the last five years of actual emissions. Therefore, the commission has not changed the rules in response to this comment.

PC commented that the rules adopted for the implementation of SB 7 should be structured in such a way as to allow the purchase and retirement of NO_x allowables issued under the SB 7 program to be used as project emission reduction credits under SB 766. PC recommended two alternatives. First, the TNRCC could allow a retail electric provider (REP) to sell renewables to the owner of a grandfathered facility and assume that there will be a reduction in emissions per megawatt hour (MW) at the average rate of emissions per MW for the power plants in the area. The commenter stated that this is the least costly way to assure that the program will work, and since Texas is effectively an isolated electrical grid, will assure that emissions are reduced in the state. The EPA has recognized the Ozone Transport Assessment Group debates that add-on units that produce solar electricity or solar water heaters mitigate emissions. PC argued that a wind turbine, a solar water heater, or gases from landfills can similarly be rated based on capacity, converted into energy, and emissions reductions could thus be calculated. Secondly, TNRCC could allow the REP to buy and retire NO_x credits from the SB 7 trading program established in Chapter 101. This will assure that the emissions are actually reduced in the 60-county east Texas airshed, but it would add to the cost. The commenter further stated that since the transaction is on the open market, it may be far less costly than permit emission reductions purchased from the competitor; and the commission can significantly reduce the cost of the renewable energy used in the program by declaring that the renewable plants built to meet a contracted load under this program are pollution control devices as defined in Chapter 383 of the Health and Safety Code. If renewable energy installations are certified under Health and Safety Code, §383.004, the certification will exempt the owners from property taxes and allow them to qualify for pollution abatement bonds issued by local governmental units as provided by Health and Safety Code, §383.021. The combination of these two financial benefits could erase the premium price of renewable energy and make it the most cost-effective way to reduce emissions.

The commission will explore whether it has the authority to declare a renewable energy source, such as wind power, to be a pollution control device for the purposes of property tax exemptions and pollution abatement bonds. As the EBTA and permitting programs continue to develop, the commission can consider issues such as the use of add-on units that produce solar electricity or solar water heaters to reduce emissions. The commission agrees that REPs can buy and retire SB 7 allowances under Chapter 101 and that this transaction might be approved for use as a project emission reduction credit under the voluntary emission reduction permitting (VERP) program established by SB 766 as long as those allowances are not used to meet the requirements of SB 7.

One individual commented that electric utilities should be required to offer incentives to customers to replace inefficient appliances and light fixtures with cost-effective and energy saving equipment. The individual further commented that utilities should issue rebates to individuals and businesses that install renewable energy generating systems, and that utilities should be required to participate in any distributed generating project, public or private, that meets PUCT guidelines. Utilities should be required to pay a fair price for non-polluting power that they purchase from independent power producers. The commenter made several suggestions for how to increase competition among utilities, such as breaking up the distribution grid and making accessible to any qualified electric producer and having a large array of cogeneration industrial sites. The commenter urged the use of nonpolluting renewable electric energy.

These comments are beyond the scope of this rulemaking. Therefore, the commission has not made any changes in response to these comments.

One individual commented that gases from power companies could be used by oil companies to assist in the production of oil, and that these gases might not have to be reduced, they could be pumped into the ground. The commenter also noted that Russia has large gas fields and that gas could be used instead of coal.

These comments are beyond the scope of this rulemaking. Therefore, the commission has not made any changes in response to these comments.

One individual made several suggestions for how emissions could be reduced from utilities: school could be delayed to start after Labor Day when it is cooler; retail establishments could be closed on Sunday and Monday; the age for persons to obtain drivers license could be raised to take some cars off the road or persons without car insurance should be prohibited from driving; people should be required to buy insurance for six or 12-month periods; car inspection stations should be inspected to protect against fraud; busing of school children could be eliminated or the Dallas Area Rapid Transit buses should be used; teachers should be assigned to schools closest to their homes; the highways could be restructured to eliminate bottlenecks from four lanes when they merge into two or three lanes; cars from Mexico should be required to have a Texas inspection and insurance; limitations could be put on the use of fireplaces; IH-35 should be moved to the west and all trucks should be required to use IH-35 and the same for I-20; auto racing and drag racing strips should not allow the burning of fuels and car manufacturers should be required to have overdrive transmissions that activate at 55 miles per hour; Texas needs to withdraw its bid for the Olympics to cut down on traffic and flights; and the federal government should increase highway funding to cut down on traffic congestion.

The comments raise issues that are beyond the scope of this rulemaking. Therefore, the commission has not made any changes in response to these comments.

EPA-APS commented that the allowance requirements of §§101.330-101.337 constitute a mass cap and trade program, and that existing guidance for discretionary economic incentive programs (EIPs) is found in 40 CFR Subpart U. The commenter stated that draft federal guidance for EIPs was published in the *Federal Register* on September 15, 1999, and that the 60-day public comment period ends on November 15, 1999. EPA stated that the proposed allowance allocation/trading program to meet SB 7 and the VERP program to meet SB 766 will be reviewed under EPA's existing guidance if applicable, and possibly under EPA's new guidance (if finalized before the state's SIP submittal).

TUC, §39.264 requires the commission to create a mass cap and trade system to distribute emission allowances for use by grandfathered and electing EGFs. TUC, §39.264(g) and (h) requires the commission to allocate allowances to grandfathered EGFs in defined regions of the state. The specific intent of SB 7 is that total annual emissions of NO_x from grandfathered EGFs will not exceed 50% of the NO_x emissions in 1997 as reported to the commission and that for coal-fired grandfathered EGFs, the total annual emissions of SO_2 will not exceed 75% of the emissions during 1997, as reported to the commission. The adopted rules provide the requirements for both the permitting of these grandfathered EGFs, and an emission banking and trading program. These rules were proposed as a SIP revision to ensure that the reductions obtained from the program are federally enforceable and thus useful towards the reduction of criteria pollutant emissions necessary to assist nonattainment and near-nonattainment areas in meeting or continuing to meet the NAAQS. This program was designed to comply with the legislative mandate of SB 7 which in some ways is inconsistent with the requirements for discretionary EIPs. However, the commission anticipates adopting future SIP rules that will contain requirements that are more consistent with the EIP. The commission is committed to working with the EPA in its review and approval of the SB 7 program.

CPS commented that generally the proposed use and transfer of allowances is too restrictive and beyond the intent of SB 7. The commenter stated that the cap and trade program should be flexible and not have undue restrictions, which do not allow companies to make the necessary reductions in the most cost-effective and efficient manner.

Pre-proposal drafts of the EBTA contained several restrictions on trading to assist EGFs that are subject to 30 TAC Chapter 117 in meeting those SIP requirements. However, since the proposed rules eliminated the references to Chapter 117, the SIP-related restrictions were not proposed. The commission believes that the adopted rules provide flexibility for the successful implementation of the EBTA and the permitting program. The restrictions that are in the adopted rules are primarily requirements of TUC, §39.264, for example, the limitation on trading outside of the designated regions. Other restrictions, such as the monitoring provisions or the reporting requirements, are intended to provide assurance that the mandated emission reductions are actually achieved. The commission does not believe that these minimum restrictions will inhibit free trading of allowances among EGFs.

EPA-ARD commented that the banking and trading system is too restrictive. EPA-ARD felt that greater freedom would result in greater flexibility and cost savings without undermining environmental goals. They recommended that the commission consider that allowances can be banked indefinitely; however, if banked emissions exceed 10% of capped emissions, then banked allowances must be used at a rate of two allowances per actual one ton emitted.

The rules have not been revised to make the suggested change in response to this comment. The proposed §101.335(b), now §101.335(a), provides that allowances not used for compliance may be banked for use in subsequent control periods. This program was designed to comply with the legislative mandate of SB 7 which in some ways is inconsistent with the requirements for discretionary EIPs. However, the commission anticipates adopting future SIP rules that will contain requirements that are more consistent with the EIP. The commission is committed to working with the EPA in its review and approval of the SB 7 program.

EPA-ARD commented that the definitions in §101.330 do not clearly define "electing" and "non-electing" EGFs and the relationship to "grandfathered" facilities. It commented that "grandfathered facility" is used without definition in Chapter 101.

The commission agrees, and has modified the definition of "Electric generating facility" in §101.330(14) to include the term "grandfathered." This modified definition now refers to electric generating facilities that are required to obtain an EGFP. The exemption in that definition has been moved to §101.331, Applicability. The commission has changed references to "grandfathered facilities" to "grandfathered EGFs." "Grandfathered facilities" is defined in Chapter 116. The definition of "nonelecting EGF" is not necessary, and it has been deleted. The rule was also revised to include a new definition of "electric generating facility" in §101.330(12) to be used for generic references to EGFs.

B&P commented that the definition of "Broker" in §101.330(4) should be revised because it is unnecessarily vague and recommended that a "Broker" be defined as "A person not required to participate in the requirements of this division who opens an account under this division for the sole purpose of banking and trading emissions allowances." B&P also recommended that the definition of "Broker account" be revised to read "The account where allowances held by a broker are recorded." The commenter also noted that conforming changes can be made to §101.331, if the suggested changes are made.

The proposed rule did not include a definition of "Broker" in §101.330(4); however, the commission agrees that a definition is appropriate and has included one in the adopted §101.330(4). Section 101.331(2) has been revised to reflect this new definition. The commission also agrees with the suggested change to the definition of "Broker account" in §101.330(5), but has retained the second sentence regarding the use of allowances held in a broker account.

B&P commented that the definition of "Compliance account" does not fully distinguish a "compliance account" from a "broker account." Therefore, the definition for "Compliance account" should be revised to "The account where allowances held by an EGF or multiple EGFs are recorded for the purposes of meeting the requirements of this Division and Chapter 116, Subchapter I of this title."

The commission agrees that the suggested language may clarify the rule and has revised the definition of "Compliance account" in §101.330(8) accordingly.

Baker & Botts commented that the definition of "Electric generating facility" should read as follows: "A facility that generates electric energy for compensation and is owned or operated by a person in this state, including a municipal corporation, or river authority. An EGF does not include a facility that generates electric energy for internal use and that during 1997 sold, to a utility power distribution system, less than one third of its potential electrical output capacity or less than 25 MW output, whichever is greater." Baker & Botts commented that this language more clearly eliminates those units that were not intended to be covered by SB 7, such as a 20 MW station that sells half of its generated electricity (ten MW). The commenter also stated that it is clearly not the intent of SB 7 to regulate this size/type of source. TXU commented that the definition of "Electric generating facility" in §116.18(8) excludes "a facility that generates electric energy primarily for internal use but that during 1997 sold to a utility power distribution system less than 1/3 of its potential electrical output capacity." TXU believes that if it were the Legislature's intent to exclude cogeneration facilities, language would have been included in the definition found in §39.264(2). In accordance with SB 7, any facility that generates electricity for compensation should be included in the definition.

The commission has not revised the rule in response to these comments. TUC, §39.264(a)(2) provides the definition of an "electric generating facility." The SB 7 definition, and the definition of EGF in §101.330 both contain the language concerning the generation of electricity for compensation. The commission believes that cogeneration facilities that sell less than one-third of potential electrical output capacity to the utility power distribution system are generating electricity primarily for internal use and that any electricity that is sold to the distribution system is surplus and not electric energy that was originally generated for compensation. The commission agrees that the definition of electric generating facility in SB 7 does not specifically exclude these cogeneration facilities from the requirements of SB 7, nor does it prohibit the commission from revising the definition to exclude certain EGFs based on the generation of electricity for compensation. The commission has also excluded EGFs that generate power primarily for internal use, but that during 1997 sold one-third of their generated power or less than 219,000 megawatt-hours to the utility power distribution system. The exemption was modified to also exclude EGFs that sold less than 219,000 megawatt hours to a utility power distribution system. This reference was added to exempt small cogenerators who may exceed the one-third limitation. The commission believes that excluding these EGFs is consistent with SB 7 and will not negatively affect the overall emission reductions required by the program. The commission believes that an exclusion based on these criteria is sufficient and is consistent with the EPA definition in 40 CFR §72.2.

AE questioned the reasoning of selecting May 1-April 30 as the control period in §101.330(6). AE felt that this will lead to difficulties associated with the calendar year being used for emissions inventories, and recommended development of a plan that transitions the control period to one that matches the calendar year.

The rule has not been revised in response to this comment; however, the definition of "Control period" is now in §101.330(9). TUC, §39.264(c) provides "for the 12-month period beginning on May 1, 2003, and for the 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% of the total emissions of that pollutant during 1997, as reported to the conservation commission, and total annual emissions of sulfur dioxides from coal-fired facilities subject to this section may not exceed levels equal to 75% 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." Because §39.264(c) specifically defines the period of time to be used as the control period, the commission does not believe it is appropriate to use any different control period. The rule has not been revised in response to this comment.

B&P commented that §101.330(9) does not clearly define EGFs that are physically located in Texas. The commenter stated that the definition, although consistent with TUC, §39.264(a)(2), appears to encompass facilities not located in Texas so long as they are owned by a person in Texas, and that the rules should only apply to facilities that are physically located in Texas. The current definition only states "EGFs owned or operated by persons in this state." UT commented that §101.330(9) should further define "person," since this term is used in TUC, §39.264 as "individual, partnership, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, and a corporation, but does not include an electric cooperative." UT also commented that the definition of "person" does not include state institutions of higher education.

The commission has not revised the rule in response to the comment from B&P. Therefore, it is not necessary to clarify that the rules only apply to EGFs that are physically located within Texas. However, if the commission were to include such a limitation, it might prohibit the commission from defining the "El Paso Region" as being consistent with the La Paz Agreement. The La Paz Agreement designated the Paso del Norte Air Shed as the contiguous air shed basin between El Paso, Texas, Sunland Park, New Mexico, and Ciudad Juarez, Chihuahua. The La Paz Agreement does not extend the commission's jurisdiction into the State of New Mexico. Elsewhere in this response to comments, the commission states its intent for revising the definition of "El Paso Region" to be consistent with the Paso del Norte Air Shed. If the commission were to limit participation in the EBTA to only those EGFs that are physically located in Texas, then it is unlikely, in spite of the La Paz Agreement, that the El Paso Energy facility in Sunland Park, New Mexico could obtain allowances.

The commission agrees that it is appropriate to use the definition of "person" in TUC, §11.003(14) and has included a new definition in §101.330(17) and §116.18(12). This definition will apply for purposes of initial issuance of EGFPs and for the allocation of allowances. By using this definition, the commission can ensure that it will not inadvertently require additional facilities to comply with the program, since the definition of "person" in TCAA, §382.003(10) is more inclusive than the TUC definition.

B&P commented that §101.330(12), now §101.330(16), should define "NO_x allowance" consistently with the proposed definition of "SO_2 allowance," which states that an SO_2 allowance is valid only for the purposes of meeting the requirements of this division and Chapter 116, Subchapter I.

The commission agrees, and has revised the definition of "NO_x allowance" to be consistent with the definition of "SO_2 allowance."

Enron requested that §101.332(f) be revised to provide that neither a NO_x allowance nor an SO_2 allowance constitutes a security or property right, but that they may be used as collateral or security for indebtness.

The commission has not revised the rule in response to this comment. The commission believes that the use of allowances as collateral or to secure a debt is a matter best left to the owner of the allowances and the party with whom the owner is dealing. Since allowances can be reduced, such as when emissions exceed the allowances in any control period, to account for load shifting, or to invalidate allowances that were used by electing EGFs to meet SIP requirements, it is likely that this sort of provision would conflict with this statutorily based enforcement authority. Nothing in the adopted rule or TUC, §39.264 prohibits the use of allowances for collateral or security for indebtedness; however, the commission does not believe that adding this language to the rule is appropriate.

CPS commented that §101.332 restricts the use of allowances for use only in the EBTA and prohibits the use of allowances for netting, offsets, or other credits. The commenter stated that it is unclear why these NO_x allowances created for EBTA cannot be used for other trading programs, and that it seems that allowances created for use by utilities and used only within the utility sector could be traded for any program designed to reduce NO_x from that sector. CPS further commented that for example, trading should be allowed for future utility offsets if they are not needed for the EBTA program, since the NO_x reductions are still reducing overall NO_x from the same utility sector.

The commission has not revised the rule in response to this comment. TUC, §39.264 contains several restrictions on the use of allowances. TUC, §39.264(j) provides that EGFs may only trade allowances with other EGFs in the same region. TUC, §39.264(l) provides that an EGF may not trade an unused allowance for a particular air contaminant, for use as a credit for another air contaminant. TUC, §39.264(i) limits the use of allowances for electing EGFs. The pre-proposal draft of these rules did provide flexibility to EGFs that would also be subject to Chapter 117 SIP requirements; however, the proposal eliminated any links to Chapter 117. The general concern was that the limitations necessary to ensure that the allowances could be used for SIP purposes made the EBTA unwieldy and overly restrictive. Further, there are additional federal requirements that must be met in order for allowances to be used for netting or offsets. In order to ensure that the EBTA is implemented consistently with the requirements of TUC, §39.264, the adopted rule contains the minimum restrictions on trading. In the near future, the commission will be proposing additional SIP reductions that will impact EGFs and other sources in the affected areas. If it is appropriate, a trading program could be developed for facilities affected by those rules or the EBTA could be modified to accommodate EGFs that are affected by the SIP rules at that time.

B&P commented that §101.332(a) states that allowances are valid only for meeting the requirements of "this division" and cannot be used to meet the limitations of a permit or applicable rule. However, the proposed definition of "SO_2 allowance" states that allowances can be used to meet the requirements of Chapter 116, Subchapter I. The commenter stated that §101.332(a) should be revised to reflect that allowances are valid for meeting the requirements of Chapter 116, Subchapter I.

The commission agrees with the suggested change and has corrected §101.332(a).

CSW, TXU, Entergy, AECT, CT&W, Group A, Entergy Services, and CPS recommended that §101.332(b) be revised to provide a 30-day period after the end of each control period for owners/operators of EGFs to reconcile the allowance accounts, by changing May 1 to June 1. Reliant requested a 60-day period and suggested that the rule be revised to extend the period to June 30. CSW and TXU also requested language clarifying that this section should only apply to EGFs that are subject to this division. SPS commented that the proposed language was not clear, consistent, or reasonable relating to reconciliation periods. SPS proposed that 60 days (consistent with Acid Rain Program) would be acceptable for emission data to be quality assured and for transfer transactions to be completed if necessary.

The commission agrees that 30 days for EGFs to reconcile its allowance account is appropriate and §101.332(b) has been revised. The commission reminds EGFs that if additional allowances are necessary but unavailable, the EGF will be out of compliance with the requirements of the EBTA in the EGFP. EGFs now have until June 1 after every control period to sell or purchase allowances in order to reconcile the amount of allowances in their compliance account to ensure that the number of allowances in their account are equal to, or exceed, the amount of emissions from the prior control period.

Reliant commented that §101.332(c) should be revised to allow the creation of discreet emission reduction credits (DERC) for those facilities that have early implementation of reductions required under the EBTA program.

The commission agrees that early reductions that meet the requirements of §101.29 could be banked as DERCs. Section 101.332(c) does not eliminate this possibility.

EPA-APS noted that §101.332(c) states that emissions reductions used to satisfy the requirements of the EBTA cannot be used to generate emission reduction credits (ERC) or DERCs. EPA-APS commented that since allowances may be banked and traded annually, it would clarify the intent of this section to state that any emission control equipment installed or other measures undertaken to not exceed the allowances in the compliance account cannot be used for ERCs or DERCs under TNRCC's emissions banking and trading program found in §101.29 or other banking/trading programs such as Chapter 117.

The commission has not revised the rule in response to this comment. The commission agrees that reductions cannot be used to meet the requirements of SB 7 and also be banked as DERCs or ERCs because the reductions cannot be counted twice. The commission will allow for reductions that are surplus to either be banked as allowances or DERCs or ERCs, as long as the reduction meets the requirements of §101.29, Emission Credit Banking and Trading.

EPA-ARD asked whether "the emission reduction credits or discrete emissions reductions credits are related to a particular rule such as Chapter 117, Subchapter B, Division 2."

The DERCs and ERCs are related to a variety of rules, such as 30 TAC Chapter 115, Control of Air Pollution from Volatile Organic Compounds, and Chapter 117, Control of Air Pollution from Nitrogen Compounds. Section 101.29 provides a complete listing of uses for ERCs and DERCs.

EPA-ARD commented that §101.332(h) mentions two cases where there would be one compliance account. It suggested that language may be needed to address situations where there are multiple EGFs at the same property, but not under common ownership and control.

The commission agrees with the comment and has revised the definition of "Compliance account" in §101.330(8) to clarify that EGFs not under common ownership or control may have separate compliance accounts.

Lloyd Gosselink commented under §101.332(h) that facilities with multiple EGFs should be allowed to have multiple compliance accounts, and that having one compliance account will present practical problems because different EGFs may be under different regulatory requirements. For example, permitted EGFs are currently required to report on an annual basis on January 1 of each year; however, grandfathered EGFs are required to report on an annual basis ending on May 1 of each year. The commenter stated that subsection (h) should be deleted because of these problems.

The commission believes that assigning one compliance account for multiple EGFs under common ownership or control will properly structure the allotment and tracking of allowances. The reporting requirements for the control periods for electing EGFs and grandfathered EGFs are the same. Any reporting requirements under Chapter 116, Subchapter B for electing EGFs are based on a calendar year and are not associated with the reporting requirements for the EBTA and Chapter 116, Subchapter I.

EPA-ARD commented that §101.332(i), while appropriate, may not be sufficient to spur sources to comply. EPA-ARD asked whether other penalty provisions apply.

The commission has not revised the rule in response to this comment; however, the commission has moved §101.332(i) to §101.333(4) for clarity. Section 101.330(i) is based on TUC, §39.264(n)(2) and authorizes the commission to reduce allowances for the next control period for an EGF that emits an air contaminant in excess of the EGF's allowances. In addition to that provision, subsection (n) provides that the commission may enforce administrative penalties in an amount determined by the commission for each ton of emissions by which the EGF exceeds its allowances. TUC, §39.264(o) states that the commission can penalize an EGF that exceeds its allowances by ordering the EGF to shut down or to take other enforcement action as provided by commission rules. The commission believes that these provisions are sufficient to ensure compliance with the EGFPs and the EBTA.

SPS and Entergy commented that the database used to obtain heat input values for calculation of NO_x allowances should reflect actual measurement of fuel combusted and added that the EPA Acid Rain Database contains values that are generally related to actual fuel consumption. SPS, Entergy, Group A, and CPS commented that the same database should be applied to both grandfathered and electing facilities. CT&W commented that the proposed method for calculating emission allowances using EPA's Acid Rain Database in §101.333 is the most accurate, and suggested that the commission make use of it for all allowance calculations. CSW, Reliant, Brazos Electric, Entergy Services, and AECT suggested that §101.333(2) be revised to specify that the amount of allowances allocated to electing EGFs will be equal to the actual emissions in tons in the 1997 EPA Acid Rain Database, provided that the number of tons do not exceed the allowable emissions in NSR permit for that electing EGF or the maximum annual emissions under any applicable state or federal requirement. CSW and Reliant commented that this request is intended to make the calculation of allowances on a consistent basis for all EGFs.

TUC, §39.264(h) specifies the formula to be used for the calculation of allowances for grandfathered EGFs. That section also specifies emission rates to be met within each region. As stated in the proposal preamble, the 1997 Emissions Scorecard from EPA's Acid Rain Program is the basis of the emission rates specified in TUC, §39.264(h) for grandfathered EGFs. These emission rates are necessary to achieve the required 50% reductions in NO_x and 25% reductions in SO_2. The commission agrees that it would be appropriate to use the EPA Acid Rain Program Database as the basis for calculating allowances for electing EGFs and has revised §101.333(2) to include a reference to the 1997 Emissions Scorecard from EPA's Acid Rain Program.

Reliant commented that §101.333(1) should be clarified to state that "ER = emissions rate, as defined in subparagraphs (C) or (D) of this paragraph." Lloyd Gosselink commented that there are problems with the sentence structure of §101.333(1). A conjunction "or" follows the end of subparagraph (A), but not subparagraph (B). Also, the equation formula legend includes a reference to a subparagraph (E), which was not proposed. EPA-APS also commented that §101.333(E) does not exist and requested clarification by either adding the omitted subparagraph (E) or changing the definition of ER as the emission rate defined in subparagraph (C) or (D). EPA-ARD commented that in §101.333(1)(E), emission rates referenced in Chapter 117 should be more specific.

The commission agrees that the proposed §101.333(1) contained typographical errors and an erroneous reference to a nonexisting subparagraph (E), and has revised the rule so that it has the appropriate conjunctions, numbering, and lettering. These changes are not substantive and have not changed the meaning of the section.

EPA-ARD commented that it is not clear in §101.333(1) which sources receive allocations under the first equation and asked if it would be used for grandfathered facilities. EPA-ARD also questioned whether the limits in §101.333(2) limit the allocation in 101.333(1).

The commission has revised the rule to clarify that grandfathered EGFs are the facilities that are given allowances under §101.333(1). The limits in §101.333(2) are applicable only to electing EGFs to ensure that emission reductions used for the EBTA are real and non-surplus.

EPA-ARD commented that §101.333(1)(A) and (B) is ambiguous when it refers to "Acid rain database." EPA-ARD suggested that it would be clearer if the language specified "1997 Emissions Scorecard from EPA's Acid Rain Program."

The commission agrees, and has revised the rule to refer to the "1997 Emissions Scorecard from EPA's Acid Rain Program." The proposed §101.333(1)(A) and (B) have been deleted, and the specification for the acid rain database is now in the formula in §101.333(1) for heat input.

EPA-ARD commented in §101.333(1)(C)(ii) that it is unclear if the 1.38 lb/mm BTU limit for SO_2 applies to all EGFs, or only coal-fired sources.

The commission agrees that this section was unclear and has revised §101.333(1)(C)(iii), now §101.333(1)(A)(ii), to clarify that the 1.38 lb/mm BTU limit for SO_2 applies to only coal-fired grandfathered EGFs.

EPA-ARD commented in §101.333(1)(D) that clarification is needed for the emission rate used for SO_2.

The commission has made no changes in response to this comment; however, §101.333(1)(D) has been moved to §101.333(1)(B) for clarity. TUC, §39.264 did not specify an SO_2 emission rate for grandfathered EGFs in the West Texas or the El Paso Region, because there are no coal-fired grandfathered EGFs in these regions.

AE and Lloyd Gosselink commented that there should be an alternative means for determining NO_x/SO_2 allowance allocations if the applicant can demonstrate that the base year (1997) was an abnormal year for system operation. AE offered a possible alternative scenario: if the applicant could demonstrate that the standard allocation, based on 1997 process values, was more than 20% less than the average of the three-year period of 1996 to 1998 inclusive, the average of these three years would be the base allocation for that unit. Lloyd Gosselink proposed that the final rules include a component, for example, the facility's capacity factor for the year, to take into account actual operating hours during the 1997 base year. The commenter stated that this component will allow the TNRCC and the operator to extrapolate an annual emission rate based on the actual emissions level and the actual operating hours for the facility during 1997. Lloyd Gosselink proposed the following revision to §101.333(1)(A): "HI = total heat input (million British thermal units (MMBtu)) during 1997, determine by subparagraphs (a) or (b) of this paragraph which may be adjusted to an annualized figure to account for unit outages and load growth." LP&L commented that the use of maximum capacity during the past five years of emissions data would allow for more competitive flexibility while still meeting the intended emissions reduction goal, and that by using one year of emissions data (1997) the Legislature did not consider important aspects, such as load swing (when a utility can purchase electricity cheaper than it can produce it). The commenter stated that every generation source that did not produce or had fewer production hours in 1997 will have its operational ability restrained with a reduction in its ability to compete in a deregulated market. LP&L also acknowledged that the requirement to base allowances on one year of heat input data is a basic part of the legislation, and that the commission is bound by this requirement.

The commission has made no changes in response to these comments. TUC, §39.264(h) specifies that the commission shall allocate allowances based on a facility's total heat input in terms of MMBtu during 1997. The commission believes that the provisions of TUC, §39.264(h) do not provide the commission with the discretion to create a different formula or emission rates for the purpose of meeting the mandated reductions of 50% for NO_x and 25% for SO_2.

Lloyd Gosselink commented that §101.333(1)(A) conflicts with the Electric Reliability Council of Texas (ERCOT) designation of Garland's utilities as "must run" facilities. This designation requires Garland's units to operate near capacity during the summer months in order to provide adequate and reliable electricity. The commenter stated that based on the proposed language, Garland may be forced to reduce electric generation in order to meet emission reduction mandates, possibly causing brownouts during the summer months.

The commission has made no changes in response to this comment. ERCOT-designated "must run" grandfathered EGFs are not among the exemptions from the requirements to operate in compliance with the EBTA as prescribed by TUC, §39.264. The commission does not believe that TUC, §39.264 requires reductions in electric generation, since each grandfathered EGF has the option of complying with SB 7 emission reduction requirements by installing emission controls, acquiring additional allowances, or reducing electric generation. Further, electing EGFs that are designated as "must run" facilities are not required to participate in the EBTA.

CSW, Entergy, AE, CEED, Entergy Services, Group A, AECT, and CPS commented that §101.333(2) should allow the owner/operator of electing EGFs to decide whether allowance(s) should be allocated for NO_x, SO_2, or both. By mandating that an electing EGF obtain allowances for both NO_x and SO_2, AE felt that participation will be severely limited. CPS commented that mandating electing facilities to obtain allowances for both NO_x and SO_2, will limit, rather than broaden, the range of cost-effective alternatives available to utilities to achieve the requirements of TUC, §39.264; and have no effect on achieving compliance with the emissions limitations prescribed by TUC, §39.264(c). CPS commented that it is not the intent of SB 7 to require additional limitations or reductions on emissions from permitted facilities.

The commission has not revised the rule in response to this comment. The commission believes that the language in TUC, §39.264(i) requires electing EGFs to be given allowances for both NO_x and if applicable, SO_2. TUC, §39.264(i) provides that "a person, municipal corporation, electric cooperative or river authority that is 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)." TUC, §39.264(i) refers to the emission limitations in TUC, §39.264(c). TUC, §39.264(c) provides "for the 12-month period beginning on May 1, 2003, and for the 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% 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% 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." TUC, §39.264(c) also refers to "facilities subject to this section." The phrase "this section" in TUC, §39.264(i) refers to TUC, §39.264 in its entirety and not to the specific requirements of subsection (i). Thus, if an owner or operator elects to designate an EGF 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 electing EGF is now subject to all of the applicable requirements of TUC, §39.264, including the requirements of TUC, §39.264(c). Since TUC, §39.264(c) requires specific reductions of NO_x and SO_2, electing EGFs will be given allowances consistent with the requirements of TUC, §39.264(i) for the purpose of meeting the emission reductions required by TUC, §39.264(c). Because the commission believes that the language in TUC, §39.264(i) requires electing EGFs to be given allowances for both NO_x and if applicable, SO_2, the adopted rule has not been revised in response to the comments.

EPA-APS commented that §101.333(2)(C) should be revised to state that the amount of allowances for electing EGFs shall not exceed an applicable state or federal requirement. The commenter stated that a federal requirement may include, but not be limited to, reasonably available control technology (RACT) and/or reductions from sources in an ozone nonattainment area or any or all portions of the Texas Clean Air Strategy area contained in an emissions inventory utilized in an attainment demonstration which has been submitted to the EPA for approval as part of a SIP.

The commission agrees that the amount of allowances for electing EGFs may not exceed applicable state and federal requirements. The commission believes that the proposed language in §101.333(2)(c) addressed this issue. The adopted rule has not been revised in response to this comment; however, §101.333(2)(C) is now in §101.333(2)(B). Nothing in §39.264 limits the allowances for electing EGFs to ozone nonattainment area or any or all portions of the Texas Clean Air Strategy area contained in an emissions inventory utilized in an attainment demonstration which has been submitted to the EPA for approval as part of a SIP. Therefore, the commission does not believe that revising the rule to include these limitations is necessary.

EPA-APS commented that a new §101.333(2)(D) should be added to state that for electing EGFs located in ozone nonattainment areas, the amount of allowances shall not exceed the 1990 emissions inventory or the emissions reported in any Rate-of-Progress SIP submitted for the ozone nonattainment area, or the emissions based on limitations established by regulations in the attainment demonstration SIP.

The commission has not revised the rule in response to this comment. TUC, §39.264(i)(2) provides that allowances for electing EGFs shall be allocated in an amount equal to each facility's actual emissions in tons in 1997. TUC, §39.264(i)(4) allows emission reductions from electing EGFs to be used to satisfy emission reductions for grandfathered EGFs to the extent that reductions used to meet TUC, §39.264(c) are beyond the requirements of any other state or federal standard, or both. However, nothing in §39.264 limits the allowances for electing EGFs to 1990 emissions inventory or the emissions reported in any Rate-of-Progress SIP submitted for the ozone nonattainment area. Therefore, the commission does not believe that revising the rule to include these limitations is necessary.

CSW, Reliant, TXU, Entergy, Entergy Services, Group A, AECT, and CPS requested that §101.333(3) be deleted. CSW, TXU, AECT, and Entergy also requested that the statement in the preamble that future rulemakings addressing future ozone SIP reductions will reduce the allowances allocated under SB 7 be deleted. CSW and Reliant commented that these allowable reductions are contrary to the intent of §39.264 of SB 7, are unwieldy, and are unfair to grandfathered facilities. CSW and Reliant also commented that the allowance allocation and trading provisions in SB 7 are a limited-purpose mechanism for implementing a cap and trade program to allow flexibility in achieving regional reductions of NO_x and SO_2, and not an all-purpose system for limiting emissions for grandfathered and electing EGFs. CSW and Reliant commented that the SB 7 allowance system should remain distinct from the ozone SIP and any other applicable requirement. Brazos Electric suggested substitute wording that would track the language of TUC, §39.264(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."

The commission has deleted the proposed §101.333(3) because the proposed rule did not provide for allowing facilities subject to Chapter 117 to use the EBTA program. The adopted §101.333(3) implements §39.264(i)(4) to prevent double counting of emissions reductions by allowing the commission to invalidate allowances, authorizing emissions in excess of applicable state or federal requirements that are allocated to an electing EGF. This is necessary to account for state and federal regulations that became effective during the prior control period and for regulations that specify emission rates instead of an emission cap. The commission has revised the adopted preamble to reflect the fact that the trading program for future ozone SIP requirements has not yet been developed. The proposed rule did not include limitations that would be necessary to allow the EBTA to be used as a SIP trading program. The commission believes the adopted rule is consistent with the requirements of §39.264.

EDF commented that §101.333(4)(B) requires the TNRCC to allocate allowances annually, but that TUC, §39.264(h) implies that the intent was to allocate allowances only once no later than January 1, 2000. EDF believes that allocating allowances every year is labor-intensive and unnecessary, since the allocation will always be based on 1997 values, regardless if allocated once or every year. EPA-ARD commented that §101.333(4)(C) is unclear on whether the allowance allocations are permanent, and recommended allocating allowances for a few years at a time to allow EGFs to plan for compliance.

The commission agrees that allowances should be allocated only one time and has revised §101.333(5)(C) to state that allowances for a grandfathered or electing EGF shall be the same as their initial allocations and that compliance accounts will be automatically updated at the beginning of each control period. However, §101.333(6) provides that after the annual update to the compliance accounts, the number of allowances may be adjusted after the commission reviews the final trading reports required by §101.336. The commission must be able to adjust allowances in order to implement certain provisions of TUC, §39.264. For example, §101.332(i), which is based on TUC, §39.264(n), provides that the penalty for exceeding allowances allocated in a prior control period is to reduce allowances for the next control period in an amount equal to the emissions exceeding the allowances in the compliance account. Other examples include a facility that volunteers to permanently reduce the number of annual allowances allotted to its compliance account in order to generate DERCs or ERCs, allowances for electing EGFs that are reduced to comply with other state and federal regulations, and allowances that are reduced for electing EGFs that reduce utilization or shut down.

CSW commented that §101.333(4)(C) should be revised to require the TNRCC to allocate allowances for electing EGFs through rulemaking rather than orders.

The commission has made no changes in response to this comment. TUC, §39.264(f) requires the commission to develop rules to provide for the allocation of allowances. It does not require the specific allowances for each affected EGF to be stipulated in the rules. The commission believes that it is sufficient to establish in the rule the procedure by which allowances will be allocated. Additionally, the commission's using an order to allocate allowances will provide a less resource-intensive method to allocate or revise as necessary allowances for affected EGFs.

TXU, Lloyd Gosselink, and CEED commented that §101.333(5) should be revised to eliminate the requirement that the registry include the price paid per allowance. Omitting the price paid for allowance is consistent with the EPA Acid Rain Program, and including the price on the registry could actually inhibit trading.

The commission has made no changes in response to this comment. The commission believes that including the price paid per allowance in the registry will improve trading and selling of allowances by providing an open and competitive market system. Providing as much information as possible in the registry will allow participants in the EBTA to make informed transactions. For organizational clarity, §101.333(5) has been renumbered to §101.333(7).

CPS commented that SB 7 language states that electing EGFs cannot transfer allowances created by "reduced utilization or shutdown." CPS believes that this language was included to prevent companies from reducing their power output to produce excess allowances. The commenter stated that the formulas provided in §101.334 are overly complicated and do not seem to accomplish this purpose. The commenter further stated that the formulas include emission factors instead of just restricting the basis to utilization, and they do not account for generation that results from the replacement of thermal energy from other units as allowed in SB 7. CPS believes that the formulas should be deleted and each utility should be handled on a case-by-case basis, because each utility has unique circumstances under which it will replace lost energy. CSW, Entergy Services, and AECT commented that §101.334(e)(2) and §101.335(a) need to include the exception language from TUC, §39.264(i)(3). CSW commented that the formulas and remaining language in §101.334(e) conflict with §39.264(I)(3) and that §101.334(e) must be revised. TXU commented that SB 7 does not prohibit trading of allowances caused from reduced utilization or shutdown, but proposed that §101.334 and §101.335 have tighter restrictions. TXU recommended that §101.334 and §101.335 be revised to allow transfers and banking of allowances resulting from reduced utilization or shutdowns as long as the reduced utilization or shutdown results from the replacement of thermal energy from the electing EGF with thermal energy generated by any other EGF. Entergy, Group A, and CPS commented that the use and transfer of allowances should be in accordance with the requirements and language of SB 7 and should be no more restrictive than provided by law. EPA-APS commented that the term "reduced utilization" in §101.334(e) is not clearly defined. The commenter stated that for some, it may mean having less heat input to the emissions unit than in 1997, and for others, it may mean generating less electricity at the emission unit than in 1997. Still for others, it may mean operating for fewer hours during the year than in 1997. Others may consider that operating at a reduced load factor (say at 75% for the year compared to 85% in 1997) is reduced utilization. EPA-APS recommended including a definition of "Reduced utilization" in §101.330, or revising §101.334(e) to state that allowances at electing EGFs that result from reduced utilization, which means an emission unit operating for fewer hours during the control period than it did in 1997 (or other appropriate meaning) or shutdowns, are ineligible for transfer.

TUC, §39.264(i)(3) specifies that an electing EGF may not transfer or bank allowances conserved as a result of reduced utilization or shutdown, unless the reduced utilization or shutdown results from the replacement of thermal energy from the electing EGF with thermal energy generated by any other EGF. The equations in the proposed §101.334(e) were to be used to calculate the number of the annual allowances allocated to an electing EGF that would be eligible for trading or banking. The commission agrees that these equations did not completely address the intent of SB 7 with regard to reduced utilization or shutdown of electing EGFs. Accordingly, the equations have been revised in the adopted §101.334(1), (2), and (3) to allow the calculation of the number of allowances that will be deducted from an EGF's compliance account for emissions that occurred during each control period.

The equation in §101.334(1) will be used for all grandfathered EGFs, and for electing EGFs with equal or increased utilization (i.e., the heat input for the control period equaled or exceeded the heat input for 1997). In this case, the number of allowances deducted from the compliance account will equal the number of tons of actual emissions during the control period.

The equations in §101.334(2) and (3) will be used for electing EGFs with reduced utilization for the control period (i.e., the heat input for the control period was less than the heat input for 1997). For these cases, the commission agrees that determining the appropriate equation to use should be done on a case-by-case basis.

The equation in §101.334(2) will be used for cases where the reduced utilization or shutdown was not replaced by thermal energy generated by another unit. In accordance with §39.264(i)(3), allowances will be deducted from the compliance account to reflect what emissions from the electing EGF would have been using 1997 heat input.

The equation in §101.334(3) will be used for cases where the reduced utilization or shutdown was replaced by thermal energy generated by another EGF. In these cases, allowances will be deducted from the compliance account for each ton of actual emissions, if any, from the electing EGF for the control period. In addition, allowances will also be deducted from the electing EGF's compliance account for each actual ton of emissions that result when the displaced thermal energy is generated by the other EGF. In cases where the EGF to which the thermal energy was transferred can be identified, the emission factor for that EGF will be used in determining the allowances to deduct. This allows the electing EGF to keep more allowances if the thermal energy is transferred to an EGF with a low emission factor. In those cases where the EGF to which the thermal energy was transferred cannot be identified, the thermal energy is assumed to be transferred to various EGFs in the state. As an estimate of emissions in this case, the equation uses the average emission factor for the state based on the 1997 Emissions Scorecard for the EPA Acid Rain Program. Using the state average emission factor encourages decreased utilization of electing EGFs that have a higher emission factor than the state average.

EPA-ARD asked, concerning §101.334(e)(1), whether the equation is necessary when the heat input for the control period is greater than that of 1997. EPA-ARD also asked whether the emission factor in §101.334(e)(1) and (2) is a measured emission rate in pounds/MMBtu and if so, from which sources of information. The commenter then asked if the equations could ever yield negative numbers and if so, what a negative result would mean.

The provisions of the proposed §101.334(e) were revised and are now in §101.334(2) and (3) for organizational clarity. The commission believes that because the heat input and emission factors can fluctuate, the formula is necessary to accurately determine the amount of allowances, if any, that can be transferred. A negative result indicates that actual emissions exceeded allocated allowances; therefore, no allowances are available for trading, unless additional allowances have been purchased. The commission agrees that clarification needs to be added as to the source of the emission factors and has revised §101.334(e)(1) and (2) and §116.914(e) accordingly.

Brazos Electric commented that §101.334 restricts transfer of allowances more than contemplated by the language of SB 7. The commenter stated that specifically, TUC, §39.264 makes no requirements for "authorized account representatives," prohibitions on transfers before May 1, 2003, or the tables of allowances set forth in §101.334(e)(1) and (2).

In order to ensure that the allowances allocated to each participating EGF are properly tracked and traded, the commission believes that it is necessary to designate an individual or individuals who have the recognized authority to transfer and manage allowances. This designation is necessary for the commission to ensure that transfers are valid and not fraudulent. The commission does not believe that this is a restriction on the trading program that will inhibit trading. The proposal stated that the delay in the start of the trading program was necessary to allow sufficient time to develop a tracking system for the transfer of allowances. Further, the commission expects to adopt SIP revisions that will require additional emission reductions from EGFs in attainment and nonattainment areas. The commission anticipates that these future SIP reductions may impact the EBTA and that it would be premature to allow for actual trading to begin prior to the adoption of the SIP regulations. The commission understands the need to begin planning for trades and does not believe that the restriction on actual trading will prohibit EGFs from creating contracts or other agreements that will be used for trading after the start of the program. The commission's response concerning §101.334(e) is addressed elsewhere in this response to comments.

Brazos Electric commented that while TUC, §39.264(j) restricts transfer of allowances between regions (as proposed in §101.334(f)), an exception should be made for transfers within the same company:

The commission has made no changes in response to this comment. TUC, §39.264(j), states that allocations (allowances) can only be traded within the same region. Therefore, trading cannot be made between regions, even if they are within the same company. However, companies that have multiple locations within the same region are not prohibited from trading with each other.

Sierra Club commented that trading should be limited to the same airshed, the same nonattainment area, and the same area of influence affecting the nonattainment area so that the trades pass the "laugh test."

The restrictions on trading are consistent with the requirements of TUC, §39.264, which defines specific regions of the state and limits trading of allowances to EGFs within the same region. TUC, §39.264 does not include any restrictions on trading with regard to nonattainment areas or airsheds.

TXU commented the reductions from electing EGFs may be used only to the extent that they are beyond the requirement of any other state or federal standard and that this provision does not change the allowance allocation, it only restricts how many allowances can be transferred from electing EGFs to other EGFs. TXU suggested that §101.334 could be revised to add a restriction in the transfer of allowances from electing EGFs to other EGFs.

The commission has made no changes in response to this comment. TUC, §39.264(i)(4) allows emission reductions from electing EGFs to be used to satisfy emission reductions for grandfathered EGFs to the extent that reductions used to meet TUC, §39.264(c) are beyond the requirements of any other state or federal standard, or both. The commission believes that allowances that are allocated to an electing EGF that authorize emissions in excess of applicable state or federal requirements must be invalidated to prevent reductions from being counted twice. Section 101.333(3) was revised to allow the commission to invalidate allowances allocated to electing EGFs that authorize emissions beyond state or federal requirements.

Reliant commented that §101.334(a) should be revised to read as follows: "Allowances may be transferred at any time after May 1, 2003," and suggested deleting the phrase "during the control period."

The adopted version of §101.334 is a new section called "Allowance Deductions." Some of the portions of the proposed §101.334 have been moved to §101.335, now called "Allowance, Banking, and Trading." The former §101.334(a) is now in §101.335(b). New §101.335(b) provides that allowances may be transferred at any time during a control period. This subsection is intended to define the time period for transfers, not the time period for the beginning of the EBTA program. That issue is addressed in the new §101.335(c).

EPA-ARD commented that there appears to be a contradiction in the required notification date for transfer of allowances. Section 101.334(b) allows a facility to document a transfer no later than June 30 following the control period. Section 101.334(d) requires notification within 30 days after the transfer, and §101.332(b) requires all transfers to be done by May 1. B&P commented that proposed language in §101.334(b) and (d) and §101.336(b) includes three separate documentation, notification, and reporting requirements. The commenter stated that TNRCC should delete §101.334(b), because TNRCC will already have received notification of all transfers under §101.334(d). If §101.334(b) is not deleted, it should be revised to allow documentation of final transfers and the emissions report be submitted on June 30. EPA-ARD commented in §101.334(b) that 60 days is sufficient to finish transfers and submit notification. Reliant commented that §101.336(b) should be revised to allow the report to be submitted by August 1 of each year instead of June 1.

In the new §101.335(b)(2), the commission requires notification within 30 days of transfer for timely maintenance of compliance account records. The 60-day notification required in §101.334(b), now located in §101.336(b), will serve as confirmation that the transfers of which the commission received notification under §101.335(b)(2), formerly §101.334(d), occurred, and will allow the commission to timely reconcile all compliance accounts. The commission has modified §101.336(b) to allow final reports to be submitted no later than June 30 following the control period. The commission believes that submittal of these reports as quickly as reasonably possible is critical to expedite the review and reconciliation of compliance accounts to allot allowances for the next control period. The commission believes that 60 days is a reasonable time frame for this purpose.

EPE commented that the allowance mechanism under SB 7 should be consistent with the allowance transaction mechanism used under Part 75 and the Acid Rain Program. EPE also commented that the frequency of allowance reporting should match the reporting of allowances and emissions under the Part 75 rules.

The commission believes that the allowance and reporting requirements are consistent with the control period required by TUC, §39.264. Further, the requirement to report after each trade and the reconciliation period will allow the commission to maintain an up-to-date registry consistent with the control period. The rules have not been changed in response to this comment.

EPA-ARD commented that subsections (a), (b), (d), and (e) in §101.334 could be reorganized or combined for clarity. EPA-ARD also commented that §101.334(a) and (d) do not clarify who may transfer allowances and who must notify whom of the transfers.

As stated previously, most of the provisions in §101.334 have been moved to §101.335 for clarity and organization. The commission agrees that the rule was unclear as to who may transfer allowances and who is being notified about transfers. The rule has been revised to clarify that allowances are transferred by authorized account representatives and that notification of transfers of allowances must be provided to the commission. Section 101.334(a) is now §101.335(b). Section 101.334(b) is now §101.336(b). Section 101.334(c) is now §101.335(b)(1). Section 101.334(d) is now §101.335(b)(2). Section 101.334(f) is now §101.335(d), and §101.334(g) is now §101.335(e).

B&P commented that §101.334(d) states that allowance transfers are prohibited prior to May 1, 2003, and that this is justified in the proposed preamble to allow the TNRCC to create the appropriate tracking system. The commenter stated that there does not appear to be any justification for prohibiting allowance transfers for more than three years after the initial allocation of allowances; thus, B&P recommended that §101.334(d) be modified to allow transfers soon after January 1, 2000 (recommended six months after).

The commission has not made changes in response to this comment; however, §101.334(d) is now §101.335(b)(2). The proposal stated that the delay in the start of the trading program was necessary to allow sufficient time to develop a tracking system for the transfer of allowances. Further, the commission expects to adopt SIP revisions that will require additional emission reductions from EGFs in attainment and nonattainment areas. The commission anticipates that these future SIP reductions may impact the EBTA and that it would be premature to allow for actual trading to begin prior to the adoption of the SIP regulations. The commission understands the need to begin planning for trades and does not believe that the restriction on actual trading will prohibit EGFs from creating contracts or other agreements that will be used for trading after the start of the program.

B&P commented that §101.334(f) should be revised to clarify that EGFs in the El Paso Region can use credits obtained from Juarez, Mexico, as provided in proposed §101.337(a).

The commission has not revised the rule in response to this comment. Section §101.334(f), now §101.335(d), provides that allowances may not be transferred between regions. Section §101.337(a) provides that an EGF in the El Paso Region can meet the emission allowances by using credits obtained from reductions in the City of Juarez, United States of Mexico. Elsewhere in the response to comments in this adopted preamble, the commission states its intent for revising the definition of "El Paso Region" to be consistent with the Paso del Norte Air Shed. The Paso del Norte Air Shed includes the City of Juarez and Sunland Park, New Mexico. Since the El Paso Region will be defined to include the City of Juarez, it is not necessary to revise the new §101.335(d).

EPA-ARD commented that in §101.334(h)(1)(C) and (K), allowances will need to be tagged (region, nonattainment status, grandfathered, permitted, etc.), in order for brokers and buyers to know whether they are following the restrictions of trading.

The subparagraphs to which EPA-ARD refers were not included in the proposed rules. However, allowances will be tracked and recorded by the TNRCC. The allowance registry will note the original owner of the allowances, the location of the EGF, whether the allowance was allocated to a grandfathered or electing EGF, and all other pertinent information to support the EBTA.

SPS commented that if the TNRCC must reconcile emissions to an annual cap each year, there will have to be compensation for excess allowances that must be retired. The commenter also stated that the TNRCC would have to establish some type of buy-back program to limit the available allowances in any given year.

The commission has made no changes to the rules in response to this comment. Previous drafts of §101.335 limited the life of allowances to one year. The adopted §101.335(b) provides that allowances not used for compliance may be banked for use in subsequent years. Thus, the commission does not believe that the change would be needed because allowances do not expire.

PC commented that in §101.335 the commission should give an incentive to utilities to retire their oldest plants or to go further in reducing emissions by modifying §101.335 to allow owners of grandfathered power plants to bank for two years any reductions resulting from the retirement or extra cleanups. PC added that additional years of credit should be given for EGFs that make additional reductions, like three years for a permitted power plant and five years on a retired power plant.

Although electing EGFs may not transfer or bank allowances that are conserved as a result of reduced utilization or shutdown, grandfathered EGFs are not subject to the same limitation. Therefore, utilities have an incentive to shut down grandfathered EGFs, because they are allowed to keep the allowances in perpetuity. Section 101.335(a) already provides that allowances not used for compliance may be banked for use in subsequent years. There is no limitation in the adopted rule on the amount of time that allowances may be banked. The commission believes that the adopted rule contains the incentive for grandfathered EGFs to be retired or make additional reductions.

EPA-ARD commented that in §101.335(a), the term "electing facilities" should read "electing EGFs." B&P commented that there are several instances in the proposed rules where the undefined term "electing facilities" is used rather than the defined term "electing EGFs."

The commission agrees, and has revised all references to "electing facilities" throughout Chapter 101 to "electing EGFs." The provision in §101.335(a), concerning "electing facilities" and "reduced utilization or shutdown" was deleted, because the new formulas in §101.334(2) and (3) address the issue.

EPA-ARD questioned why §101.335(b) limits banking to one year, and stated that this may reduce the incentives for over-complying with the program. SPS commented that no restrictions should be placed on allowances except those specifically mentioned in SB 7. The commenter also stated that SB 7 does not limit the life of an allowance; in fact, §39.264(k)(2) refers to using allowances in later years (plural). Reliant commented that §101.335(b) should be revised as: "Allowances not used for compliance during a control period may be banked for use in subsequent control periods." The commenter stated that this change clarifies that allowances may be banked and used in subsequent control periods. The word "years" may lead to confusion, since "control periods" is the term used throughout the proposal.

The proposed rule did not contain a limitation in §101.335(b), now §101.335(a), concerning the number of years the allowances could be banked. The commission agrees that the word "years" should be deleted from the new §101.335(a) and has revised the rule to refer to "control periods."

EPE and CT&W commented that in §101.337(a), the intent of the Legislature was to include Ciudad Juarez, Mexico, Sunland Park, New Mexico, and El Paso County as the contiguous geographic area where an EGF may meet the emission allowances by using credit from emissions reductions achieved anywhere in the contiguous airshed, provided that certain criteria are met.

The commission has revised the definition of "El Paso Region" in §101.330(13) to include Ciudad Juarez, Mexico, and Sunland Park, New Mexico. CT&W provided with its comments a copy of the May 20, 1999 House Journal, "CSSB 7 - Statement of Legislative Intent," in support of its contention that the Legislature considered the purpose of the La Paz agreement as supporting the legislative intent for SB 7. That statement says in part that "The Act officially designated the Paso del Norte Air Shed as the contiguous air shed basin between El Paso, Texas, Sunland Park, New Mexico, and Ciudad Juarez, Chihuahua." TUC, §39.264(g) provides that the El Paso Region includes El Paso County. There is no express prohibition in TUC, §39.264(g) that prevents the commission from defining the El Paso Region as also including Ciudad Juarez, Mexico, and Sunland Park, New Mexico. The inclusion of Sunland Park, New Mexico will give further effect to the specific provisions of TUC, §39.264 concerning the El Paso Region, since it will provide EPE with additional options for meeting the emission reductions required for the El Paso region.

EPE and B&P commented on §101.337(a) that creditable reductions from Juarez are not limited to reductions from EGFs and asked the commission to confirm this position.

The commission agrees that creditable reductions from Juarez are not limited to reductions from EGFs. Since the rule as proposed does not limit creditable reductions from Juarez to EGFs only, no changes were made to the adopted §101.337(a).

CT&W commented that §101.337(a)(1)(A) should be revised to add language to clarify how reductions in Mexico will be enforceable. The commenter suggested that this intent could be met by adding a special provision to EPE's permit related to a contemplated or proposed emissions reduction from Ciudad Juarez. In that way, the commission will be able to enforce EPE's performance of that emission reduction project. CT&W stated that if the commission is unwilling or unable to interpret and apply the provision regarding Ciudad Juarez in this manner, it should be deleted.

The commission believes that the enforcement issues concerning ERCs from the City of Juarez would best be addressed on a case-by-case basis. This could be done through the use of special conditions in EGFPs as allowed by §116.913(b). By not including limitations in the adopted rule concerning the enforcement of emission reductions in the City of Juarez, EGFs in the El Paso Region can propose new and innovative strategies to obtain reductions from facilities in the City of Juarez. Thus, the commission does not believe that it is appropriate to revise or delete §101.337(a)(1)(A), since the reductions must be enforceable.

B&P commented that §101.337(a)(1)(B) requires emissions reductions in Juarez to be permanent, meaning that the emission reduction is unchanging for the remaining life of the source. The commenter stated that because an emission reduction could be "permanent" even though it changes (the emission reduction could increase), the definition should be revised by removing the statement that "permanent" means unchanging.

The commission has made no changes to the rule in response to this comment. If additional reductions are made, they would be considered to be a new reduction. Any reductions relied upon for an allowance would have to remain unchanged and permanent.

EPE, B&P, and CT&W commented that §101.337(b) exempts EGFs in the El Paso Region if the TNRCC determines that NO_x reductions in the area would result in an increased ambient ozone level. The TNRCC states in the proposed preamble that the NO_x waiver (§182(f)) that has been granted for the El Paso Region does not satisfy the criteria of this section. The commenter stated that this interpretation is not consistent with legislative intent and should be corrected.

TUC, §39.264(q) requires that the commission or EPA demonstrate that reductions in NO_x would result in an increase in ambient ozone levels in order to be exempt from the NO_x reduction requirements of §39.264. Neither the EPA nor the commission have made this determination. The §182(f) waiver indicates that NO_x reductions have not been shown in a SIP to be necessary for the attainment of the federal ozone standard. This is not equivalent to saying that NO_x reductions will cause an increase in ozone levels; therefore, the commission believes that the NO_x reduction requirements of TUC, §39.264 apply in El Paso County and has not changed the rule.

STATUTORY AUTHORITY

The new sections are adopted under TUC, §39.264, which authorizes the commission to develop rules for the allocation of emission allowances to EGFs and to make rules concerning the banking and trading of those allowances. The new sections are also adopted under Texas Health and Safety Code, TCAA, §382.011, which authorizes the commission to administer the requirements of the TCAA; §382.012, which provides the commission with the authority to develop a comprehensive plan for the state's air; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; §382.023, which authorizes the commission to issue orders; and §382.061, which authorizes the commission to delegate permitting authority to the executive director; and Texas Water Code, §5.122, which authorizes the commission to delegate uncontested matters to the executive director.

§101.330. Definitions.

The following words and terms, when used in this division, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Allowance–The authorization to emit one ton of nitrogen oxides (NO_x) or sulfur dioxide (SO_2) during a control period.

(2) Authorized account representative–The responsible person who is authorized, in writing, to transfer and otherwise manage allowances.

(3) Banked allowance–An allowance which is not used to reconcile emissions in the designated year of allocation, but which is carried forward into future years and noted in the compliance or broker account as "banked."

(4) Broker–A person not required to participate in the requirements of this division who opens an account under this division for the purpose of banking and trading emissions allowances.

(5) Broker account–The account where allowances held by a broker are recorded. Allowances held in a broker account may not be used to satisfy compliance requirements for this division.

(6) Coal–All solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388 92 ''Standard Classification of Coals by Rank'' (as incorporated by reference in Title 40 Code of Federal Regulations, §72.13 (effective June 25, 1999)).

(7) Coal-fired–The combustion of fuel consisting of coal as defined in paragraph (6) of this section or any coal-derived fuel (except coal-derived gaseous fuels with a sulfur content no greater than natural gas), alone or in combination with any other fuel. The definition is independent of the percentage of coal or coal-derived fuel consumed during any control period.

(8) Compliance account–The account where allowances held by an EGF or multiple EGFs are recorded for the purposes of meeting the requirements of this division and Chapter 116, Subchapter I of this title (relating to Electric Generating Facility Permits). EGFs not under common ownership or control may have separate compliance accounts.

(9) Control period–The 12-month period beginning May 1 of each year and ending April 30 of the following year. Control periods begin May 1, 2003.

(10) East Texas Region–All counties traversed by or east of Interstate Highway 35 north of San Antonio or traversed by or east of Interstate Highway 37 south of San Antonio, and also including Bexar, Bosque, Coryell, Hood, Parker, Somerville, and Wise Counties.

(11) Electing EGF–An electric generating facility permitted under Chapter 116, Subchapter B of this title (relating to New Source Review Permits) which is not subject to the requirements of Texas Utility Code, §39.264 and elects to comply with Chapter 116, Subchapter I of this title (relating to Electric Generating Facility Permits).

(12) Electric generating facility (EGF)–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.

(13) El Paso Region–All of El Paso County, Ciudad Juarez, Mexico, and Sunland Park, New Mexico.

(14) Grandfathered EGF–A facility that is not subject to the requirement to obtain a permit under TCAA, §382.0518(g), and 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.

(15) Heat input–The heat derived from the combustion of any fuel at an EGF. Heat input does not include the heat derived from reheated combustion air, recirculated flue gas, or exhaust from other sources.

(16) NO_x allowance–An authorization to emit is valid only for the purposes of meeting the requirements of this division and Chapter 116, Subchapter I of this title.

(17) Person–For the purpose of initial issuance of permits under Chapter 116, Subchapter I of this title, and for the issuance of allowances under this division, a person includes an individual, a partnership of two or more persons having a joint or common interest, a mutual or cooperative association, and a corporation, but does not include an electric cooperative.

(18) SO_2 allowance–An authorization to emit SO_2 valid only for the purposes for meeting the requirements of this division and Chapter 116, Subchapter I of this title.

(19) West Texas Region–All counties not contained in the East Texas Region or El Paso Region.

§101.331. Applicability.

This division applies only to the following:

(1) electric generating facilities permitted under Chapter 116, Subchapter I of this title (relating to Electric Generating Facility Permits); and

(2) brokers.

§101.332. General Provisions.

(a) Allowances are valid only for the purposes of meeting the requirements of this division and for meeting the requirements of Chapter 116, Subchapter I of this title (relating to Electric Generating Facility Permits), and cannot be used to meet or exceed the limitations of any annual emission limitation authorized under Chapter 116, Subchapter B of this title (relating to New Source Review Permits) or any applicable rule or law.

(b) On June 1 after every control period, a grandfathered or electing electric generating facility (EGF) shall hold a quantity of allowances in its compliance account that is equal to or greater than the total emissions of that air contaminant emitted during the prior control period. Compliance with the allowance system will begin with the control period beginning May 1, 2003.

(c) Emission reductions used to satisfy the requirements of the Emissions Banking and Trading of Allowances (EBTA) program cannot be used to generate emission reduction credits or discrete emission reduction credits.

(d) Allowances cannot be used for netting requirements to avoid the applicability of federal and state new source review (NSR) requirements.

(e) Allowances cannot be used to satisfy offset requirements for new or modified sources subject to federal nonattainment NSR requirements.

(f) An allowance does not constitute a security or a property right.

(g) All allowances will be allocated, transferred, or used as whole allowances. To determine the number of whole allowances, the number of allowances will be rounded down for decimals less than 0.50 and rounded up for decimals of 0.50 or greater.

(h) One compliance account shall be used for multiple EGFs permitted under Chapter 116, Subchapter I of this title located at the same property and under common ownership or control.

§101.333. Allocation of Allowances.

Allowances will be allocated according to the requirements of this section.

(1) Except as provided in paragraphs (2) and (3) of this section, allowances will be calculated for grandfathered electric generating facilities (EGF) using the following equation:
Figure: 30 TAC §101.333(1)

(A) In the East Texas Region:

(i) 0.14 pound nitrogen oxides (NO_x) per MMBtu; and

(ii) 1.38 pounds sulfur dioxide (SO_2) per MMBtu only for coal-fired grandfathered EGFs.

(B) In the West Texas and El Paso Regions, 0.195 pound per MMBtu.

(2) For electing EGFs, the amount of allowances is equal to emissions as listed in the 1997 Emissions Scorecard from EPA's Acid Rain Program, or if not listed in the 1997 Emissions Scorecard, by a method approved by the executive director, consistent with the emission reduction requirements of this division; and in both cases, shall not exceed any of the following:

(A) any annual emission limitation authorized under Chapter 116, Subchapter B of this title (relating to New Source Review Permits);

(B) an applicable state or federal requirement.

(3) The commission may invalidate any allowances allocated to an electing EGF that authorize emissions in excess of applicable state or federal requirements.

(4) If emissions of NO_x or, if applicable, SO_2, exceed the amount of allowances for a given control period, allowances for the next control period will be reduced in an amount equal to the emissions exceeding the allowances in the compliance account.

(5) Allowances will be allocated:

(A) initially, by:

(i) January 1, 2000, for grandfathered EGFs;

(ii) January 1, 2001, for electing EGFs; and municipal corporations, electric cooperatives, and river authorities that choose to obtain a permit under Chapter 116, Subchapter I of this title (relating to Electric Generating Facility Permits) for any grandfathered or electing EGFs previously exempted under §116.910(d) of this title (relating to Applicability);

(B) subsequently, by May 1 of each year, beginning in 2004.

(C) allowances will be allocated:

(i) initially by commission order for all grandfathered and electing EGFs;

(ii) notwithstanding clause (iii) of this subparagraph, at the beginning of each control period, the commission will deposit the same amount of allowances into each grandfathered or electing EGF's compliance account;

(iii) for electing EGFs, the annual deposit for any control period may be adjusted to reflect new state or federal requirements.

(6) Allowances may be deducted from compliance accounts following the review of trading reports required under §101.336(b) of this title (relating to Emission Monitoring, Compliance, Demonstration, and Reporting).

(7) The commission shall maintain a registry of the allowances in each compliance account. For each transfer, the registry shall include the price paid per allowance. The registry shall not contain proprietary information.

§101.334. Allowance Deductions.

Allowances will be deducted from a grandfathered or electing electric generating facility's (EGF) compliance account for a control period based upon the following.

(1) The following will have deducted from their compliance accounts allowances equal to the number of tons of air contaminant emitted during the control period as reported in compliance with §101.336 (relating to Emission Monitoring, Compliance Demonstration, and Reporting.

(A) grandfathered EGFs; and

(B) electing EGFs whose heat input for the control period is equal to or greater than its heat input for 1997;

(C) electing EGFs whose heat input for the control period is less than its heat input for 1997 where the reduced utilization or shutdown has been replaced by another EGF permitted under Chapter 116, Subchapter I of this title (relating to Electric Generating Facility Permits).

(2) For electing EGFs whose heat input for the control period is less than the heat input for 1997 and whose reduced utilization or shutdown has not been replaced by another EGF, allowances will be deducted from the compliance account according to the following equation:
Figure: 30 TAC §101.334(2)

(3) For electing EGFs whose heat input for the control period is less than the heat input for 1997 and whose reduced utilization or shutdown has been replaced by another EGF not permitted under Chapter 116, Subchapter I of this title, allowances will be deducted from the compliance account according to the following equation:
Figure: 30 TAC §101.334(3)

§101.335. Allowance Banking and Trading.

(a) Allowances not used for compliance during a control period may be banked for use in subsequent control periods. Allowances may only be used for the control period for which they were allocated or subsequent control periods, and may only be used within the same region where they were originally allocated.

(b) Allowances may be traded at any time during the control period.

(1) Only authorized account representatives may trade allowances.

(2) Notification of trades must occur within 30 days after the trade.

(c) Allowance trades are prohibited prior to May 1, 2003.

(d) Traded allowances held in compliance accounts must have originated from electric generating facilities in the same region.

(e) Allowances may be held only in compliance accounts for use by EGFs located in the region in which the allowances were originally allocated or in broker accounts.

§101.336. Emission Monitoring, Compliance Demonstration, and Reporting.

(a) Emission monitoring and reporting shall be conducted in accordance with §116.914 of this title (relating to Emissions Monitoring and Reporting Requirements).

(b) For each control period, grandfathered or electing electric generating facilities (EGF), must submit a report to the commission by June 30 of each year detailing the following:

(1) the amount of emissions of each allocated air contaminant during the preceding control period.

(2) a summary of all final trades for the preceding control period.

§101.337. El Paso Region.

(a) A grandfathered or electing electric generating facility (EGF) in the El Paso Region may meet the emissions allowances by using credits from emissions reductions achieved in the City of Juarez, United States of Mexico and from EGFs located in Sunland Park, New Mexico. Emission reductions under this section must meet the following criteria.

(1) The emission reduction must be:

(A) enforceable by the commission;

(B) permanent, meaning that the emission reduction is unchanging for the remaining life of the source;

(C) quantifiable, so that the emission reduction can be measured or estimated with confidence using replicable techniques;

(D) surplus, such that the emission reduction is not otherwise required of a facility by a state or federal law, regulation, or agreed order; and

(E) a real reduction in which actual emissions are reduced.

(2) The emission reduction must be reviewed and approved by the executive director prior to converting the credits into allowances under this program.

(b) Grandfathered and electing EGFs in the El Paso Region are exempt from the requirements of this division if either EPA or the commission determines that reductions of nitrogen oxides in the El Paso Region that would otherwise be required under this division would result in an increased ambient ozone level in El Paso County.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9909014

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Effective date: January 11, 2000
Proposal publication date: September 10, 1999
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Chapter 116. CONTROL OF AIR POLLUTION BY PERMITS FOR NEW CONSTRUCTION OR MODIFICATION

The Texas Natural Resource Conservation Commission (commission) adopts new §116.16, concerning Voluntary Emission Reduction Permit Definitions; §116.810, concerning Eligibility; §116.811, concerning Voluntary Emission Reduction Permit Application; §116.812, concerning Project Emission Reduction Credits; §116.813, concerning Application Review Schedule; §116.814, concerning General and Special Conditions; §116.816, concerning Deferral of Emission Reductions; §116.820, concerning Modifications; §116.840, concerning Public Participation for Initial Issuance; §116.841, concerning Notice and Comment Hearings for Initial Issuance; §116.842, concerning Notice of Final Action; §116.850, concerning Voluntary Emission Reduction Permit Application Fee; §116.860, concerning Voluntary Emission Reduction Permit Renewal; and §116.870, concerning Delegation. These new sections implement those portions of Senate Bill (SB) 766, 76th Legislature, 1999, that require the commission to create a voluntary emission reduction permit (VERP) program. These new sections will be placed in a new Subchapter H, concerning Voluntary Emission Reduction Permit.

The commission also adopts new §116.601, concerning Types of Standard Permits; §116.602, concerning Issuance of Standard Permits; §116.603, concerning Public Participation in Issuance of Standard Permits; §116.604, concerning Duration and Renewal of Registrations to Use Standard Permits; §116.605, concerning Standard Permit Amendment and Revocation; §116.606, concerning Delegation; and amendments to §116.610, concerning Applicability; §116.611, concerning Registration to use a Standard Permit; and §116.614, concerning Standard Permit Fees. These new sections and amendments implement those portions of SB 766 that authorize the commission to issue standard permits. The commission also intends §§116.601-116.605, 116.610, 116.611, and 116.614 to be revisions to the state implementation plan (SIP).

Sections 116.16, 116.601, 116.603, 116.604, 116.605, 116.614, 116.810, 116.811, 116.812, 116.816, 116.840, 116.842, and 116.850 are adopted with changes to the proposed text as published in the September 10, 1999 issue of the *Texas Register* (24 TexReg 7148). The remaining sections are adopted without changes and will not be republished.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES CONCERNING VERPS

During the 75th legislative session in 1997, House Bill (HB) 3019 directed the commission to develop a voluntary emissions reduction plan for the permitting of existing significant sources. These existing significant sources are commonly known as grandfathered facilities. A grandfathered facility is one that existed at the time the legislature amended the Texas Clean Air Act (TCAA) in 1971. These facilities were not required to comply with (i.e., grandfathered from) the then new requirement to obtain permits for construction or modifications of facilities that emit air contaminants. If grandfathered facilities have not been modified, they continue to be authorized to operate without a permit. Beginning in the early 1990s, efforts were made to develop concepts and provide incentives to bring grandfathered facilities into the permit program. The intent of HB 3019 was to create a program that would encourage the remaining grandfathered facilities to voluntarily obtain permits that would reduce the emissions from those facilities. In response to the legislative directive in HB 3019, the commission appointed an 11-member advisory panel to provide recommendations regarding the criteria for a voluntary emission reductions plan for grandfathered facilities. This committee, the Clean Air Responsibility Enterprise (CARE) Committee, consisted of representatives from local governments, the environmental community, and industry groups, and met several times in the fall of 1997 to provide the commission with recommendations. Those recommendations were presented to the commission at the December 18, 1997, Commissioner's Work Session. The commission held several hearings to obtain comments on the recommendations made by the CARE committee and received comments from the public and industry groups.

In order to implement the recommendations of the CARE committee and the requirements of HB 3019, the 76th Legislature passed SB 766 in 1999. In general, SB 766 recategorizes the new source review authorizations under the TCAA and creates the new program for the voluntary permitting of grandfathered facilities. Prior to the revisions by SB 766, the TCAA authorized the commission to issue permits for the construction or modification of facilities that will emit air contaminants; standard permits adopted by rule; and exemptions from permitting, also adopted by rule. SB 766 modified this structure by authorizing the commission to issue standard permits using a process that does not require each standard permit to be in a rule. A new authorization–permits by rule–was created for the construction of certain types of insignificant facilities. Exemptions from permitting now authorize only changes at insignificant facilities. Finally, the commission is now authorized to develop criteria for facilities that emit a *de minimis* amount of air contaminants that do not need preconstruction authorization. Within the category of permits, SB 766 created two new permitting options: the VERP program for permitting of grandfathered facilities, and the multiple plant permit. As a part of the VERP program and with this adoption, the commission is creating an emission reduction credit program for use by grandfathered facilities that are unable to meet the control method requirements of the VERP program.

SB 766 also provided several incentives for grandfathered facilities to apply for a permit under the VERP program. Section 11 of the bill provides that not later than January 15, 2001, the commission shall prepare a report on the number of companies that have obtained or applied for a VERP and the reductions in emissions anticipated. The report shall be submitted to the governor, the lieutenant governor, the speaker of the House of Representatives, the chair of the Senate Committee on Natural Resources, and the chair of the House Committee on Environmental Regulation. Section 12 of the bill states that the commission may not initiate an enforcement action against a person for the failure to obtain a preconstruction permit under TCAA, §382.0518, concerning Preconstruction Permit, or a rule adopted or order issued by the commission under that section, that is related to the modification of a facility that may emit air contaminants if, on or before August 31, 2001, the person files an application for a VERP. Section 12 does not apply to an act related to the modification of a facility that occurs after March 1, 1999. The bill also amended TCAA, §382.0621(d) to require increasing emission fees for the largest grandfathered facilities which do not participate in the VERP program by the dates established. The fee increases will be proposed in rulemaking scheduled for February 2000.

This adoption implements two of the new requirements of SB 766, the VERP program and the new process for issuing standard permits. The authority for the VERP program is in TCAA, §382.0519, concerning Voluntary Emissions Reduction Permit; §382.05191, concerning Voluntary Emissions Reduction Permit: Notice and Hearing; §382.05192, concerning Review and Renewal of Voluntary Emissions Reduction Permit; and §382.05193, concerning Emissions Permits Through Emissions Reduction. The new process for issuance of standard permits is authorized by TCAA, §382.05195, concerning Standard Permit. The remaining elements of SB 766, including emissions fees, multiple plant permits, permits by rule, and *de minimis* criteria, will be addressed in rulemaking scheduled for proposal in February 2000.

This adoption provides a significant amount of flexibility to owners and operators of grandfathered facilities to voluntarily make cost-effective emissions reductions. Applications for a VERP are voluntary and applicants must demonstrate the ability to meet flexible control options not available to new permitted facilities. For a grandfathered facility to be eligible for a VERP, an application must be submitted before September 1, 2001.

SECTION BY SECTION DESCRIPTION

The new §116.16 defines "airshed." For grandfathered facilities in a nonattainment area, an airshed is defined as the nonattainment area in which it is located. Nonattainment areas are geographic areas which exceed a National Ambient Air Quality Standard (NAAQS). Nonattainment areas are defined in §101.1, concerning Definitions. For facilities in attainment areas, the airshed is defined as the East Texas Region or the West Texas Region, or El Paso County. The East Texas Region and the West Texas Region are defined in a concurrent adoption concerning Chapter 101 in this issue of the *Texas Register* for implementation of certain provisions of SB 7, 76th Legislature, 1999, concerning Emissions Banking and Trading of Allowances for Grandfathered Electric Generating Facilities.

The requirements applicable to VERPs are placed in a new Subchapter H of Chapter 116. Consistent with TCAA, §382.0519(a), the new §116.810 requires VERP applications to be submitted before September 1, 2001. The adoption requires that applications be submitted under the seal of a Texas licensed professional engineer, if required under §116.110(e). The owner–or one authorized to act for the owner–of a facility, group of facilities, or account is responsible for compliance with the requirements of Subchapter H.

The new §116.811 describes VERP application requirements, and states that emissions from the grandfathered facility issued a VERP will comply with the intent of the TCAA. TCAA, §382.0519(c), provides that the commission may not issue a VERP if it finds that the emissions from the grandfathered facility will not meet the control methods specified in TCAA, §382.0519(b), or will not be protective of public health and property. The requirement to protect physical health and property is included in §116.811(1). Because of these requirements, the commission will conduct a health effects review for each

VERP application. The majority of the CARE Committee recommended that a company seeking a VERP should be required to undergo an abbreviated health effects review, as appropriate. A minority report of the CARE Committee also contained recommendations regarding health effects reviews and they are summarized in the Analysis of Testimony in this preamble.

If an applicant proposes an allowable emission rate which represents a reduction in actual emissions from the highest rate emitted over the prior three years, an abbreviated health effects review would automatically be performed. If there are proposed allowable emissions higher than the highest rate emitted over the prior three years, the commission will consider other factors when determining if an abbreviated health effects review is appropriate. Those factors include: whether best available control technology (BACT) is being proposed; whether the controls required by the VERP program are already being used; the proximity of the nearest off-property receptor; whether any monitoring data exists which indicates that no adverse off-property impacts will occur; whether the applicant proposes to use fenceline or stack monitoring technology to demonstrate ongoing protection of public health; and whether emissions reductions should be determined from emission rates over other representative periods. The commission believes that this approach will protect public health and provide incentives for reductions in emissions from the 1997 survey of grandfathered facilities. If the commission determines that an abbreviated health effects review is not appropriate, a routine health effects review will be done consistent with the commission's Technical Guidance Package concerning Modeling and Effects Review Applicability (RG-324, August 1998). Copies of this document are available from the commission's Office of Permitting, Remediation, and Registration. The VERP may also have provisions for the measurement of air contaminants, including installation of sampling ports and platforms, portable analyzers, or emission calculations.

Section 116.811(3) implements the control requirements and emission reduction options consistent with TCAA, §382.0519(b). Generally, the facility must be able to use an air pollution control method that is at least as beneficial as the BACT that the commission required or would have required for a facility, of the same class or type, as a condition for permitting 120 months prior to an application for a VERP (ten-year-old BACT), considering the age and remaining useful life of the facility. A nonattainment area is a geographic area of the state where monitored air contaminant levels are in excess of a NAAQS. Facilities located in a nonattainment or near-nonattainment area for a criteria pollutant must use the more stringent of either ten-year-old BACT or a control technology that the commission finds is generally achievable for facilities in the same area and of the same type permitted by a VERP, considering the age and remaining useful life of the facility. Solely for the purposes of the VERP program, the commission lists the following attainment counties as near-nonattainment areas for ozone: Bexar, Gregg, Harrison, Nueces, Smith, Travis, and Victoria. These counties are derived from HB 1, Article VI, §13, 76th Legislature, 1999 (the General Appropriations Act), which allocates funding for air quality planning activities in the following areas considered to be near-nonattainment for the ozone standards under the Federal Clean Air Act Amendments of 1990: Austin, Corpus Christi, Longview-Tyler-Marshall, San Antonio, and Victoria. In order to provide for a consistent starting point for determining what constitutes GACT, the commission will use the first-tier of BACT (i.e., the control technology used by a representative number of identical facilities). The stringency of GACT may be adjusted, as necessary, according to the area in which the facility is located and considering the age and remaining useful life of the facility. This method should provide for GACT determinations which are as consistent as possible. Consistent with TCAA, §382.0519(e), the new §116.816 authorizes the commission to defer required emission reductions if certain conditions are met. In addition, §116.811 provides that if an owner or operator of a grandfathered facility is unable to make the reductions required to obtain a VERP, they may meet the requirements by acquiring project emission reduction credits (PERCs) under the program in the new §116.812.

In order to be consistent with the current review process for permits and applicable federal requirements, §116.811 requires grandfathered facilities applying for VERPs to be able to demonstrate compliance with applicable federal New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS). Facilities must be able to meet performance standards specified in the application and may be required to provide information that demonstrates ongoing compliance after the permit is issued. If applicable, facilities would be required to comply with Prevention of Significant Deterioration (PSD) and nonattainment review as specified in Subchapter B of Chapter 116. Since grandfathered facilities must comply with federal requirements, if applicable, it is appropriate to ensure that these facilities are in compliance with federal requirements in the process of reviewing VERP applications. If a routine health effects review is required, the facility may be required to submit air dispersion modeling. The VERP application would identify each facility to be included in the VERP, identify the air contaminants emitted, and provide emission rate calculations, propose a control method, and identify the date by which the control method will be implemented.

The new §116.812 establishes procedures and conditions under which PERCs may be obtained. PERCs must result in emission reductions in the airshed in which the grandfathered facility is located. The PERCs must provide reductions comparable to the reductions that would be achieved through ten-year-old BACT or GACT, and the reductions must be made from one or more facilities in Texas.

The new §116.812 provides a list of qualifying emission reduction projects that includes, but is not limited to, generation of electric energy by a low-emission method (wind, biomass gasification, and solar power), the purchase and destruction of high-emission automobiles or other mobile sources, the reduction of emissions from a permitted facility that emits air contaminants to a level significantly below the levels necessary to comply with the facility's permit, a carpooling or alternative transportation program for the owner's or operator's employees, telecommuting for the owner's or operator's employees, or switching of a motor vehicle fleet operated by the owner or operator to a lower-sulfur fuel than required or an alternative fuel approved by the commission. Facilities must provide specific information in applications for a VERP concerning any proposal to use the qualifying emission reduction projects for the creation of PERCs. The commission will provide guidance, as needed, for the implementation of this program, including qualification of credits.

Section 116.812 also requires that applications for VERPs with PERCs demonstrate that the emission reductions will be permanent, quantifiable, enforceable by the commission, real reductions in actual emissions, and not be required of a facility by a state or federal law, regulation, or agreed order.

These requirements are generally accepted for creation of emission reduction credits and are used in the commission's existing emissions credit banking and trading program. Credits under the PERC program are not transferable consistent with TCAA, §382.05193(f). A VERP that authorizes a PERC will contain specific conditions that require the successful completion of the project. This will ensure that the anticipated emissions reductions actually occur in a reasonable amount of time.

The new §116.813 requires the commission to process VERP applications under §116.114, concerning Application Review Schedule, and as required by TCAA, §382.0519(f), to give priority to processing VERP applications for grandfathered facilities located less than two miles from schools, day care centers, nursing homes, or hospitals. The new §116.814 allows the commission to include general and special conditions within the VERP and requires holders of VERPs to comply with the general and special conditions contained in §116.115, concerning General and Special Conditions.

The new §116.816 implements the provisions of TCAA, §382.0519(e), and authorizes the commission to issue permits that defer reductions in emissions of certain air contaminants only if the applicant will make substantial reductions in other specific air contaminants based on a prioritization of contaminants considering local, regional, and state air quality needs. The legislature intended very limited use of deferrals. An applicant must clearly document that exceptional economic hardship or specific technical impracticability problems are a barrier to implementing the reductions required by a VERP (SB 766-Statement of Legislative Intent Adoption of Conference Committee Report). When prioritizing air quality needs to determine whether to grant a deferral, the commission proposes to consider: the location of the grandfathered facility; the size of the reduction of emissions of other specific air contaminants and whether the reductions are in addition to the reductions that are required for other specific air contaminants by §116.811(3); the impact of the reduction of emissions of other specific air contaminants and the deferral on attaining NAAQS; anticipated state or federal regulations that may require reductions of the air contaminants being deferred; and the benefit to public health from the reduction of other specific air contaminants versus the deferral. As a point of clarification, deferrals are intended for grandfathered facilities which cannot meet the control requirements of the VERP program due to exceptional economic hardship or specific technical impracticability problems, as stated earlier. Applicants will not have to apply for a deferral in order to phase in controls required under the VERP program.

The new §116.820 would require that modifications of grandfathered facilities permitted under VERPs must comply with Subchapter B of Chapter 116. In other words, once a VERP has been issued, existing requirements for amending or altering permits under Subchapter B of Chapter 116 are applicable. This section implements the requirements of TCAA, §382.0519(d).

The new §116.840 requires applicants for initial issuance of a VERP to publish notice of intent to obtain a permit in accordance with Chapter 39, Subchapter H of this title, concerning Applicability and General Provisions, and Subchapter K of this title, concerning Public Notice of Air Quality Applications. Subchapters H and K implement the new requirements of TCAA, §382.056, as amended by the 76th Legislature by HB 801. Subchapter K also includes alternative means of notice for small businesses, as required by TCAA, §382.05191(b). TCAA, §382.05191 provides that public participation for initial issuance of a VERP will be done in the manner of TCAA, §382.0561, concerning Federal Operating Permit; Hearing, and §382.0562, concerning Notice of Decision. These sections allow for notice and comment hearings instead of contested case hearings under Texas Government Code, Chapter 2001, and require the commission to respond to comments and send notice of final action to persons who comment during the comment period or during a hearing. The requirements of §§116.840-116.842 are based on the sections in 30 TAC Chapter 122, concerning Federal Operating Permits, that implement the requirements of TCAA, §382.0561 and §382.0562. Section 116.840 provides that any person who may be affected by emissions from the grandfathered facility may request a notice and comment hearing on a VERP application within 30 days after the publication of notice under 30 TAC §39.418, concerning Notice of Receipt of Application and Intent to Obtain Permit. Persons affected by a decision to issue or deny a VERP may seek review as appropriate under 30 TAC Chapter 50, concerning Action on Applications and Other Authorizations and may seek judicial review under TCAA, §382.032, concerning Appeal of Commission Action.

The new §116.841 contains the hearing requirements for the initial issuance of VERPs. The rule allows the commission to decide whether to hold a hearing based on the reasonableness of a request. The commission is not required to hold a hearing if the basis of the request by a person who may be affected by emissions from a grandfathered facility is determined to be unreasonable. If a hearing is requested by a person who may be affected by emissions from a grandfathered facility, and that request is reasonable, the commission will hold a notice and comment hearing. This section requires that notice of hearing on a draft permit be published in the public notice section of one issue of a newspaper of general circulation in the municipality where the grandfathered facility is located or in the nearest municipality. The notice must be published at least 30 days prior to a hearing. The notice is published at the applicant's expense, and the rule specifies the content of the notice. The rule provides the procedures for the submission of comments at a hearing and specifically states that the period for submitting written comments extends to the close of the hearing and may be extended beyond the close of the hearing. Any person, including the applicant, may submit comments on whether the draft permit contains inappropriate conditions or whether the preliminary decision to issue or deny the VERP is inappropriate. Commenters shall raise all issues and submit all comments supporting their position by the end of the public comment period. This requirement will assist the commission in developing its response to comments as required by the new §116.842. To ensure a complete record of the comments, the rule prohibits the incorporation by reference of supporting materials for comments unless the materials meet the criteria in §116.842(g). The commission is required to keep a record of all comments submitted or raised at a hearing and to have an audio recording or written transcript of the hearing. The record is available to the public. Draft permits may be revised based on comments pertaining to whether the permit provides for compliance with the requirements of a VERP.

The new §116.842 would require the commission to individually notify persons who commented during the public comment period or at a permit hearing of the final action of the commission. The notice must be sent by first-class mail to the commenters and to the applicant. The notice must include the response to comments, the identification of any changes in the permit, and a statement that any person affected by the decision of the commission may petition for rehearing and may seek judicial review. The notice must also state that persons affected by a decision to issue or deny a VERP may seek review as appropriate under 30 TAC Chapter 50, concerning Action on Applications and Other Authorizations and may seek judicial review under TCAA, §382.032, concerning Appeal of Commission Action.

The new §116.850 requires a permit fee from VERP applicants. The amount of the application fee would vary based on the level of control, a factor that directly affects the amount of commission resources needed to review an application. Applicants who propose controls at least as stringent as ten-year-old BACT or GACT under §116.811(3)(A) and (B) would remit a flat fee of $450. The fee for ten-year-old BACT or GACT is appropriate, since determining the level of control due to the age and remaining useful life of the facility can involve extensive resources. Since GACT is a new standard for controls, the commission anticipates that this determination will require extended staff and management time. The maximum fee for a VERP for a small business, as defined in the Federal Clean Air Act (FCAA), §507(c), shall be $100, if the grandfathered facility will use a control method at least as stringent as those defined in §116.811(3)(A) or (B). Applicants proposing to defer emission reductions or to use PERCs would remit a fee of $1,000. The commission expects that extensive staff time will be required to verify the conditions of deferrals and to validate PERCs. If an applicant for a VERP at an account proposes to include more than one grandfathered facility in the VERP, the highest applicable fee would apply. However, only one fee per VERP would be required.

The new §116.860 implements the requirements of TCAA, §382.05192, which requires the renewal of a VERP in accordance with Chapter 116, Subchapter D, concerning Permit Renewals. TCAA, §382.05193(e) adds specific requirements to be considered in the renewal of a VERP that was issued based on emission credits under §116.818. To renew such a VERP, the facility owner shall have made the equipment improvements or emissions reductions necessary to meet the requirements of §116.811(3), or acquire additional credits under the program, as necessary, to meet the permit requirements.

The new §116.870 states that the commission may delegate to the executive director any action regarding a VERP. This delegation is authorized by TCAA, §382.061, which allows the commission to delegate to the executive director the powers and duties under TCAA, §§382.051-382.0563, and Texas Water Code, §5.122, which authorizes the commission to delegate uncontested matters to the executive director.

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES CONCERNING STANDARD PERMITS

SB 766 created a new process for the development and issuance of standard permits. A standard permit is applicable to new or existing similar facilities. Prior to the amendments by SB 766, standard permits were required to be developed under the rulemaking procedures of the Administrative Procedure Act. Prior to this adoption, the commission adopted standard permits under §116.617, concerning Standard Permits for Pollution Control Projects; §116.620, concerning Installation and/or Modification of Oil and Gas Facilities; and §116.621, concerning Municipal Solid Waste Landfills. The new procedures authorized by TCAA, §382.05195 required the commission to establish the criteria for issuing and amending a standard permit. The actual standard permits are no longer required to be adopted by rule. "Issuing" in this case means that the commission has developed a standard permit and made it available for use by similar facilities. This process is similar to that used for the development of general permits under the Texas Water Code. Consistent with current practice, the executive director will continue to approve registrations to use the commission-issued standard permits. The new process requires public notice, an opportunity for a public meeting, and a response to comments that is similar to the process used for rulemaking. The benefit of this new process is that it allows the standard permits to be issued and amended in an efficient manner without sacrificing public input. In addition, the process will allow the commission to quickly develop and seek comment on proposed standard permits which will benefit affected facilities as well as the public, since facilities choosing to construct under a standard permit will be limited by the conditions of the permit. Throughout the preamble and the adopted rules concerning standard permits, the existing standard permits that were developed by rule are referred to as standard permits "adopted" by the commission, while standard permits that will be developed under the new process are referred to as standard permits "issued" by the commission.

SECTION BY SECTION DISCUSSION

The new §116.601 categorizes a standard permit as one either adopted as a rule or those issued by the commission under the procedures of the new §116.603. The section includes procedures to ensure that currently-authorized facilities continue to be covered by a standard permit if an existing standard permit adopted by the commission is repealed and replaced with no changes by a standard permit issued under the new procedures. Existing registrations for the repealed permit would be automatically converted as long as the facility continues to meet the requirements.

SB 766 made a significant revision to the existing process for continued operation under a standard permit. Prior to these amendments, if a facility was authorized by a standard permit and that standard permit was revised, the facility could continue to operate under the version by which it was authorized. TCAA, §382.05195(f) specifically requires facilities authorized by a standard permit to comply with amendments to a standard permit within certain time periods. To be consistent with those requirements, the commission will now require existing standard permit holders to register and comply with the standard permit, as amended. If a standard permit adopted by the commission is repealed and replaced with a standard permit issued by the commission, and the requirements of the standard permit are changed in the process, then existing registrations will be invalidated. The facility would have to be registered under the issued standard permit by the later of either the deadline established by the commission in the issued standard permit, or the tenth anniversary of the original registration. Holders of registrations not wishing to register for the issued standard permit will have the option of applying for or qualifying for other applicable permits or exemptions from permitting.

The commission will notify, in writing, all holders of existing registrations of the date by which a new registration must be submitted. All registrations, new and existing, will be renewed according to the requirements of the new §116.604. SB 766 requires registrations to use a standard permit to be renewed. To be consistent, it is appropriate for all registrations, including those approved under the existing adopted standard permits, to be renewed.

The new §116.602 establishes the conditions under which the commission may issue a standard permit. The standard permit must be enforceable, and the commission must be able to adequately monitor compliance. Generally, facilities authorized under standard permits must use current BACT. There are two exceptions to this requirement. TCAA, §382.057 provides for a standard permit to authorize emission reduction projects that constitute reasonably available control technology under the rules adopted as part of the SIP. TCAA, §382.05195(a)(3) provides that a standard permit for grandfathered facilities applied for before September 1, 2001 is not required to meet BACT.

The new §116.603 establishes the requirements of public participation to be satisfied prior to the issuance by the commission of a standard permit. The section establishes geographic coverage for newspaper publication by the commission of proposed standard permits. The rule requires the commission to publish notice of standard permits that will have statewide applicability in a daily newspaper of largest general circulation within each of the following metropolitan areas: Amarillo, Austin, Corpus Christi, Dallas, El Paso, Houston, the Lower Rio Grande Valley, Lubbock, the Permian Basin, San Antonio, and Tyler. Notice of standard permits that affect a limited area will be published in a daily or weekly newspaper of general circulation in that area. The commission will also publish notice of all proposed standard permits in the *Texas Register*. The commission is required to publish newspaper notice of a proposed standard permit in accordance with 30 TAC §39.411, concerning Text of Public Notice, and will include an invitation for public comment with a comment period of at least 30 days. The commission is required to hold a public meeting to provide additional opportunity for public comment and to respond to any comments at the time the commission issues or denies the standard permit. A copy of the commission's response will be mailed to each person who made a comment. A notice of the commission's final action and the text of its response to comments would be published in the *Texas Register* . Copies of issued permits and responses to comments would be available for inspection at the commission's Office of Permitting, Remediation, and Registration in Austin and at the appropriate regional offices. The commission believes that these procedures will provide ample opportunity for public input into the development and issuance of standard permits.

The new §116.604 establishes the duration of a registration to use a standard permit as a term not to exceed ten years. The rule requires that the registrations be renewed by the date the registration expires. The commission will send notice of the renewal deadline to standard permit holders at least 180 days prior to expiration of the registration. Instead of requiring permit holders to submit registrations for renewal, the commission may automatically renew the registration. For example, if the standard permit is relatively simple or if no state or federal requirements have changed for that industry, it may be a more efficient use of commission and industry resources to allow the commission to automatically renew the registration. The section also provides requirements governing the renewal of registration to use standard permits.

The new §116.605 establishes the procedures for commission amendment or revocation of issued standard permits. Standard permits would remain in effect until amended or revoked. The commission will be able to amend or revoke standard permits after providing notice in the *Texas Register* and newspapers in areas affected by the standard permit, or in Austin, Dallas, and Houston if the standard permit has statewide applicability. The commission will also provide written notice to registrants and any persons requesting to be on a mailing list concerning a specific standard permit. The commission believes that these notice requirements are appropriate, since amendments to standard permits would likely be as stringent, or more stringent, than the existing standard permits. Similarly, in the unlikely event that a standard permit is revoked, it will probably be replaced with another standard permit, and affected registrants will be given individual notice.

The commission may add or delete requirements through amendment of a standard permit. The following criteria will be used by the commission to determine whether or not to amend or revoke a standard permit: whether a condition of air pollution exists; the applicability of other state or federal standards that apply or will apply to the types of facilities covered by the standard permit; requests from the regulated community or the public to amend or revoke a standard permit consistent with the requirements of the TCAA; and whether the standard permit requires BACT. The commission believes that adhering to these criteria will harmonize implementation of state and federal requirements as well as providing a measure of certainty for the regulated community. Consistent with TCAA, §382.05195(f), facilities choosing to retain standard permit authorization would be required to comply with the amendments on the later of either the deadline of the original registration renewal date or on a date otherwise provided by the commission in the amended standard permit. The commission will not require compliance with an amended standard permit earlier than 24 months after an amendment unless it is necessary to protect public health. However, standard permit registrants must still comply with changes in other state or federal requirements within the time frames stated in those requirements. Facilities may be required to register to use the amended standard permit, or if the amendments are minor, the commission may defer reregistration requirements until the original renewal date for the registration. If the commission revokes a standard permit, it will provide written notice to registrants of the revocation and inform them that other authorization must be sought. As provided by TCAA, §382.05195(g), the issuance, amendment, or revocation of a standard permit, or the issuance, renewal, or revocation of a registration to use a standard permit is not subject to Texas Government Code, Chapter 2001.

The new §116.606 states that the commission may delegate any authority in Subchapter F to the executive director. This delegation is authorized by TCAA, §382.061, which allows the commission to delegate to the executive director the powers and duties under TCAA, §§382.051-382.0563, and Texas Water Code, §5.122, which authorizes the commission to delegate uncontested matters to the executive director. The commission is not delegating the authority to issue standard permits at this time. The executive director is already authorized to approve registrations under §116.611, concerning Registration to Use a Standard Permit.

The current §116.610 contains general requirements for meeting state and federal emission limitations as conditions for entitlement to standard permits currently existing and adopted into this subchapter. The adopted amendment to §116.610 would require facilities to meet these general requirements as conditions for operation under standard permits issued by the commission as a result of this adoption. In addition, §116.610(a)(6) is deleted, since the requirement to register is stated in the new §116.604.

The amendment to §116.611 clarifies that registrations on form PI-1s are registrations to use a particular standard permit. The name of the section has been changed.

Section 116.614 is amended to clarify that the commission may waive application fees for registrations to use specific standard permits and that persons may be required to register to use specific standard permits rather than simply claiming them. This section requires fees for registrations to use an amended standard permit, or to renew a registration to use a standard permit, unless waived by the commission, or when a standard permit is automatically renewed by the commission. This fee is consistent with the permit amendment and renewal process for permits for individual facilities under Chapter 116.

FINAL REGULATORY IMPACT ANALYSIS

The commission has reviewed the rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and has determined that the rulemaking is not subject to §2001.0225 because it does not meet the definition of a "major environmental rule" as defined in that statute. "Major environmental rule" means a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure and that may adversely affect in a material way the economy, or a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. The amendments for standard permits provide streamlined processes to issue and amend standard permits. The new requirements for registration to use standard permits and registration renewals will not adversely affect, in a material way, the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. The new requirement to comply with amended standard permits is not expected to have an adverse effect because the proposed rules provide criteria to be used by the commission for determining when and if a standard permit should be amended. Permit holders would be given ample time to comply with the amended standard permit. Because the adopted amendments for a VERP are voluntary, they are not anticipated to adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. In addition, the adopted amendments do not meet any of the four applicability requirements of a "major environmental rule." Specifically, the amendments will not impose any significant additional requirements not already required by state or federal law, and the amendments do not exceed a standard set by federal law, an express requirement of state law, or a requirement of a delegation agreement. In addition, these rules and amendments are adopted under a specific state law.

TAKINGS IMPACT ASSESSMENT

The commission has completed a takings impact assessment for the amendments and new sections. The following is a summary of that assessment. These amendments and new sections authorize the VERP program. The amendments also implement a new process for issuance and amendment to standard permits and the new requirements for registrations. If an owner or operator of a grandfathered facility chooses to participate in the VERP program, it is possible that controls may be required for the facility to meet the requirements of the program. As an alternative to controls, applicants can propose a project that will provide emission reductions in an amount needed to meet the control requirements. In limited circumstances, applicants can request a deferral of the permitting of certain air contaminants if other emissions are controlled. However, this is a voluntary action at the discretion of the owner. The new requirements for permit holders to comply with amended standard permits will provide ample time for facilities to comply with the amendments, if they choose to do so. These amendments do not affect private property in a manner that restricts or limits an owner's right to the property that would otherwise exist in the absence of the governmental action. Consequently, this adoption does not meet the definition of a takings under Texas Government Code, §2007.002(5). The reductions obtained from the issuance of VERPs will assist in the efforts of the commission to attain the NAAQS. This action is taken in response to a real and substantial threat to public health and safety, and significantly advances the health and safety purpose, and imposes no greater burden than is necessary to achieve the health and safety purpose.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

The commission has determined that this rulemaking relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission's rules in 30 TAC Chapter 281, Subchapter B, concerning Consistency with Texas Coastal Management Program. As required by 31 TAC §505.11(b)(2) and 30 TAC §281.45(a)(3), relating to actions and rules subject to the CMP, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission has reviewed this action for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council. For the adopted amendments and new sections related to the authorization of VERPs, and the new process to issue standard permits, the commission has determined that the rules are consistent with the applicable CMP goal expressed in 31 TAC §501.12(1) of protecting and preserving the quality and values of coastal natural resource areas, and the policy in 31 TAC §501.14(q), which requires that the commission protect air quality in coastal areas. This adoption is intended to provide incentive to owners and operators of grandfathered facilities to make voluntary reductions. The adoption also allows the commission to issue standard permits using a streamlined and efficient process while still allowing for public participation. This action is consistent with 40 Code of Federal Regulations because it does not authorize an emission rate in excess of that specified by federal requirements.

PUBLIC HEARINGS AND COMMENTERS

The commission held public hearings on this adoption in El Paso and Lubbock on October 1, 1999, in Austin on October 4, in

Irving on October 5, and in Houston and Beaumont on October 7, 1999.

The commission received comments from 28 individuals and the following organizations and companies: People Against Contaminated Environments (PACE), Bastrop County Environmental Network (BCEN), the Sierra Club (SC), Galveston-Houston Association for Smog Prevention (GHASP), Texas Campaign for the Environment (TCE), Tarrant Coalition for Environmental Awareness (TCEA), Texas Oil and Gas Association (TxOGA), Association of Texas Intrastate Natural Gas Pipelines (ATINGP), Mobil Corporation (Mobil), GPM Gas Services Company (GPM), Coastal Corporation (Coastal), BP Amoco, Environmental Defense Fund (EDF), Baker and Botts, L.L.P., on behalf of the Texas Industry Project (TIP), Clark and Seay, L.L.P. (C&S), Brown McCarroll and Oaks Hartline, L.L.P. (BMOH), Bracewell and Patterson, L.L.P. (B&P), Mothers for Clean Air (MCA), Neighbors for Neighbors (NFN), the League of Women Voters of Texas (LWV), the Texas Compliance Advisory Panel (CAP), Public Citizen (PC), Texas Renewable Power Coalition (TRPC), Sustainable Energy and Economic Development Coalition (SEED), the United States Environmental Protection Agency (EPA), the Texas Cotton Ginner's Association (TCGA), and the El Paso Energy Corporation (EPE).

The commission also received joint comments from the following state representatives: the Honorable Glen Maxey, District 51, Austin; the Honorable Lon Burnam, District 90, Fort Worth; the Honorable Dawnna Dukes, District 50, Austin; the Honorable Ruth Jones McClendon, District 120, San Antonio; and the Honorable Zeb Zbranek, District 20, Winnie.

ANALYSIS OF TESTIMONY

BCEN supported the comments of NFN, and GPM and Coastal supported the comments filed by TxOGA and TIP.

ATINGP commented that the commission should consider developing the rules for the multiple plant permit so that maximum flexibility in operations can be conducted between the covered facilities within the confines of the PSD program.

The commission agrees that rules for the multiple plant permit should provide flexibility as long as federal New Source Review (NSR) permitting programs are not triggered. The multiple plant permit provisions will be included in the second phase of rulemaking to implement the provisions of SB 766. The second phase rules are expected to be adopted in the second quarter of 2000.

One individual made several suggestions for how emissions could be reduced: school could be delayed to start after Labor Day when it is cooler; retail establishments could be closed on Sunday and Monday; the age for persons to obtain drivers licenses could be raised to take some cars off the road or persons without car insurance should be prohibited from driving; people should be required to buy insurance for six or 12-month periods; car inspection stations should be inspected to protect against fraud; busing of school children could be eliminated or the Dallas Area Rapid Transit buses should be used; teachers should be assigned to schools closest to their homes; the highways could be restructured to eliminate bottlenecks from four lanes when they merge into two or three lanes; cars from Mexico should be required to have a Texas inspection and insurance; limitations could be put on the use of fireplaces; IH-35 should be moved to the west and all trucks should be required to use IH-35 and the same for I-20; auto racing and drag racing strips should not allow the burning of fuels and car manufacturers should be required to have overdrive transmissions that activate at 55 miles per hour; Texas needs to withdraw its bid for the Olympics to cut down on traffic and flights; and the federal government should increase highway funding to cut down on traffic congestion.

These comments raise issues that are beyond the scope of this rulemaking. Therefore, the commission has not made any changes in response to the comments.

The EPA commented that it has serious concerns about the approvability of the amnesty section because it could be taken to include amnesty for federal sources. Since nothing is included in the rule, EPA requested that the commission explain how it intends to implement that provision of SB 766.

SB 766 does not provide amnesty for facilities which should have obtained a nonattainment NSR permit or a PSD permit. Chapter 116, Subchapter B already requires, as applicable, PSD or nonattainment review.

EDF commented that the commission should include in the rules a comprehensive review of all grandfathered facilities to analyze whether major modifications have been made at each facility. Amnesty is only an incentive if there is a real threat of penalties if the companies do not volunteer. The review must be completed by the end of the period for volunteering, or within a few months thereafter, and must be accompanied by a policy statement of the commission that proceedings to recover penalties from non-volunteering offenders will be instituted in the fall of 2001. Such a review and penalty program would turn the amnesty into a meaningful incentive. Without such an effort, the amnesty is a gratuitous gift to law-breaking free riders. Finally, EDF stated that the report should indicate how many grandfathered plants are affected by the potential of higher emission fees, in order to ascertain whether the emission fee provision constitutes a meaningful incentive.

The commission believes that the amnesty provision in SB 766 was meant to provide a nonthreatening process for encouraging companies to voluntarily permit grandfathered facilities. Therefore, the commission believes that the amnesty provision is a meaningful incentive as written and needs no enhancement. As a part of the VERP application review process, applicants must verify that they meet all federal requirements. If, during the course of the VERP application review, it is discovered that the facility modified under either the TCAA or the FCAA, then the appropriate permitting actions would be required. Because the rules already provide for compliance with federal requirements, the commission has not revised the rules in response to the comments. The commission will include information in the report to the legislature about how many grandfathered plants are affected by the potential of higher emission fees in accordance with TCAA, §382.0621(d).

The CAP commented that the commission must clarify the potential enforcement implications of making a voluntary permit application. This information should be summarized in outreach materials and made available to small businesses via numerous avenues, including industry associations. Many small businesses consider themselves to be grandfathered, but in actuality may not be.

The commission agrees, and will provide guidance concerning its interpretation of the amnesty provision.

BMOH commented that the commission should make clarification in the rules that the amnesty provision applies to any grandfathered facility which obtains a VERP or a standard permit, or explain why a standard permit does not qualify for amnesty.

If the commission creates a standard permit for similar grandfathered facilities for the purpose of meeting the requirements of TCAA, §382.0519, the commission agrees that the amnesty provision would apply to qualified registrants for that standard permit. The commission is not including the amnesty provision in this adoption. Therefore, the rules have not been revised in response to this comment.

TxOGA, GPM, Coastal, BP Amoco, and TIP requested that the commission include all actions to remove facilities from grandfathered status in the online report, "Progress in Permitting Grandfathered Sources," and in the legislative reports required by SB 766, including supplemental information and resulting emission reductions. This will more accurately demonstrate the true program effects by considering reductions made though other authorizations such as standard permits, exemptions from permitting, flexible permits, or NSR permits.

The commission agrees that any permit action that meets or exceeds the VERP program should be reflected in both reports, and will do so.

TIP added that the commission should consider developing a mechanism to identify companies which plan to apply for a VERP after January 15, 2001, but before September 1, 2001. One idea might be to allow companies to submit a kind of abbreviated application or commitment to file an application before September 1, 2001.

The commission agrees that a mechanism, such as an abbreviated application or commitment letter, should be made available in order to facilitate accurate reporting to the Legislature regarding the effectiveness of the VERP program. If, upon submission of the full application, the information provided by the facility has changed, the Legislature will be updated accordingly.

EDF commented that if it is to provide the right incentives to industry and useful information to the public and policymakers, the report should include: 1) the actual reductions, to date, versus promised reductions; 2) the consequences for failing to make the promised reductions; 3) the amount of promised reductions compared to the amount of reductions which would have been achieved if the facility had met current BACT; 4) the amount of promised and actual reductions in comparison to total emissions from grandfathered facilities; and 5) the amount of additional emission reductions that other facilities and automobile owners must make in nonattainment areas under SIPs as a result of the continued grandfathering of non-volunteering plants and the less stringent standards applicable to volunteering plants.

SB 766 requires the commission to submit, no later than January 15, 2001, to the governor, the lieutenant governor, the speaker of the house, the chair of the Senate Committee on Natural Resources, and the chair of the House Committee on Environmental Regulation, a report on the number of companies that have obtained or applied for a VERP, and the reductions in emissions anticipated to result. The commission agrees that emissions reductions and their comparison to total emissions from grandfathered facilities will be included in the report. The commission also agrees that the report should include the amount of grandfathered emissions from non-volunteers. The commission does not believe it is possible to include information about the consequences for failure to make promised reductions because the report is due before the application deadline. However, enforcement of any VERP condition will be done in the same manner as any other NSR permit condition. The commission also believes that it will require extensive agency resources to tabulate information about the amount of reductions that would have been achieved using BACT as opposed to the VERP controls, and therefore disagrees that this information should be included in the report.

The EPA commented that it understands that the commission will use emission reduction credits which occur under the VERP program to help demonstrate attainment and maintenance of the NAAQS, and that it further understands that reductions will not be used for offsets and netting under federal NSR. The commenter stated that if this understanding is not correct, the commission should explain how these rules will ensure attainment and maintenance of the NAAQS and show how the rules are consistent with the FCAA. A separate EPA commenter commented that if emission reduction credits created by VERPs are to be creditable in the commission's banking and trading rules, they would have to be surplus as defined in 40 Code of Federal Regulations 51.491 to prevent the double counting of emission reductions. TIP commented that the commission should not include the emission reductions that result from the VERP program in an attainment demonstration for an area without the prior consent of the company or companies that achieve the reductions. As is the case with the current NSR program, the company that achieves those emission reductions should be allowed to preserve them as emission netting credits or for trading. Circumstances may arise where the company and the commission can reach an agreement by which some of the emission reductions are applied to attainment demonstrations. BMOH commented that the commission should provide a detailed description of the implications that the VERP reductions will have on attainment demonstrations. It is uncertain as to whether it is commission's intention to make VERP emission reductions federally enforceable, and thus not creditable toward offsets and netting calculations in nonattainment permitting exercises.

The commission did not propose the VERP program as a SIP submittal, therefore, the commission cannot, in this adoption, commit the VERP reductions to the SIP. However, the commission may do so in a future SIP submittal or use a portion, or all, of the reductions in SIP attainment demonstration modeling. Since the VERP program is voluntary, it is understood that emission reductions created through the VERP program would be creditable for netting, offsetting, or trading until such time that a SIP submittal is made where they are used in SIP attainment demonstration modeling and are demonstrated to be a necessary component of the control strategy which demonstrates attainment of the NAAQS. Prior to that time, the commission will work with the interested parties, including affected companies and the EPA, to develop an appropriate strategy for maintaining the integrity of emission reduction credits and federal permitting programs, balanced with the need to demonstrate attainment of the NAAQS. The commission agrees with the EPA that emissions reductions cannot be double counted, i.e., used for the SIP and as offsets and netting for NSR purposes. The commission also agrees with the EPA that any emission reduction credits used in the banking and trading program would have to be surplus. The term "surplus" is defined in 30 TAC §101.29(25) to mean emission reductions not otherwise required of a source by a state or federal law, regulation, or agreed order.

Most of the 28 individuals commented negatively on the proposed rules concerning VERPs. Several individuals and organizations questioned the effectiveness of the VERP program. Eight individuals commented that the VERP program should be as strict as possible, with another individual and the TCEA commenting that the VERP program should be as protective of public health as possible. TCE commented that protecting public health is more important than protecting economically inefficient old facilities. Three individuals commented that the commission should enforce reduced emissions from grandfathered plants with four more adding that the results should be closely monitored and quantified.

GHASP commented that it has steadily opposed a voluntary permitting program, and expects to realize the pollution cleanup results the governor and the commission have assured would follow from a voluntary program.

The commission understands the concerns that exist due to the voluntary nature of the VERP program and the desire for reduced emissions from grandfathered facilities and the desire for protection of public health. The commission has attempted to address these concerns by crafting a program which is flexible enough to encourage a high rate of volunteers, with incentives for encouraging actual emission reductions, while maintaining responsible review of controls and health effects. Therefore, the commission expects the VERP program to result in many grandfathered facilities being permitted, and is committed to achieving a reduction in emissions and greater protection of public health. The commission also notes that the Legislature will be monitoring the effectiveness of the VERP program, and the commission intends to provide information which is useful to the legislature and to the public in evaluating the effectiveness of the VERP program as part of the report to the Legislature, due January 15, 2001.

The EPA commented that the term "grandfathered" is nowhere defined, making it unclear to which facilities the rules apply. Although §116.10 appears to contain a definition of "grandfathered facility," it actually defines only a "qualified" grandfathered facility and not a grandfathered facility itself.

Grandfathered facility is defined in §116.10(6). The EPA referred to §116.10(2)(C), a subparagraph of the definition of "Allowable emissions."

While reviewing the definition of "Airshed" in §116.16(1), the staff noted that the definition of "El Paso Region" in the referenced §101.330, which is being adopted in a concurrent rulemaking, had been expanded to include areas outside of this state. To retain the intent of "airshed" as proposed, and to be consistent with TCAA, §382.05193, which requires PERCs to be generated in the same "airshed" from sources " in this state," §116.16(1) was amended to refer to "El Paso County" instead of the "El Paso Region."

EPE commented that the commission should require submittal under the seal of a licensed professional engineer only on those projects exceeding a capital cost of $2 million, in accordance with 30 TAC §116.110. The commenter stated that this requirement imposes unnecessary costs and discourages voluntary participation.

The commission agrees with EPE that submittal of a VERP application under the seal of a licensed professional engineer should be done only in accordance with §116.110, which includes permits resulting in a capital cost of greater than $2 million. This was the intent of the proposed §116.810(b); however, the commission has reworded this section to clarify the intent.

TCGA commented that the total number of small business grandfathered facilities is significantly more than the 50 to 100 that the agency estimated in the Small Business Analysis of the preamble of the proposed rules. The commenter believes this since there are probably 50 to 100 grandfathered cotton gins alone.

In the proposal preamble, it was necessary for the commission to estimate the number of small business grandfathered facilities because many small businesses were below the reporting threshold for the 1997 Grandfathered Sources Survey and since no agency records exist for many of them. In making the estimate, the commission believed that most of the potential small business grandfathered facilities were authorized by one or more commission exemptions from permitting or permits by rule, and would therefore not participate in or be affected by the VERP program. While using the best information at its disposal to make the estimate, the commission anticipated and appreciates comments that will more accurately reflect the number of small business grandfathered facilities. Because the VERP program is voluntary, the commission does not believe that its estimate will adversely affect the small business community. The commission, through its Small Business and Environmental Assistance Office, will work with the CAP, small business advisory committees, and trade associations, etc., to notify and assist small businesses that wish to participate in the program.

The EPA commented that the terms "grandfathered" and "account" are not defined in §116.810(c), making applicability unclear.

The term "Grandfathered facility" is defined in §116.10(6). The term "Account" is defined in §101.1, concerning Definitions.

One individual commented that a health effects review should be mandatory. Thirteen individuals, C&S, GHASP, LWV, MCA, NFN, PC, TCE, and TCEA commented that the commission should require a full health effects review, and SC commented that the commission should not streamline health effects reviews out of existence. Three individuals and the organizations added that at the very least, a full health effects review should be performed for any plant within two miles of a school, nursing home, or day care center. One individual suggested a three-mile distance and included hospitals in the list, and GHASP suggested including in the list other centers where the population is known to be especially vulnerable to the effects of air pollution. MCA commented that a separate health effects review should be done for children, because they are at increased risk of suffering from air pollution because of their size, development, and exposure. One individual, C&S, LWV, NFN, PC, and TCEA commented that a health effects review should be performed for any facility not using BACT. PC added that it was never intended for the commission to waive health effects reviews for any less stringent control measures than BACT, and that a full health effects review should be waived only if an air dispersion study is presented to the commission that shows there are no harmful emissions based on monitoring of actual emissions at the fencelines or downwind. PC also commented that the commission should use its authority to ensure that monitors are put in place near schools, nursing homes, and daycare centers to assure no adverse health effects and that monitoring should be required at remote locations as well, since many emissions come from stacks high above fence lines and travel at high altitudes.

The commission has made no changes in response to these comments. The commission will conduct a health effects review for every VERP permit issued. The minimum health effects review that the commission would perform would be to determine the amount and type of emissions, the location of the nearest off-property receptor (not just schools, nursing homes, day care centers, etc.), and to consider any compliance history relevant to off-property impacts. A full health effects review could involve conducting refined air dispersion modeling to predict off-property ground-level concentrations at off-property receptors (not just schools, nursing homes, day care centers, etc.) and comparing them with commission effects screening levels. It is the commission's goal to improve air quality through the VERP program. It is not always necessary to perform a full health effects review to accomplish that goal or to ensure that public health is protected. The commission believes that actual reductions in emissions of air contaminants from grandfathered facilities reduces off-property impacts, and therefore warrants an abbreviated health effects review. The commission also believes that it is advantageous to bring grandfathered facilities into the permitting system to evaluate existing and proposed controls, and to set limitations on emissions from those facilities. Future modifications to a facility permitted under a VERP would require a permit amendment under the permitting procedures in Chapter 116, Subchapter B, meaning implementation of BACT and the appropriate health effects review. Therefore, it is appropriate to provide for an abbreviated health effects review when actual reductions result in improved air quality.

It is not appropriate to use BACT as the sole factor to determine what level of health effects review should be performed. Other factors, especially the amount and type of emissions, the location of off-property receptors, and compliance history relative to off-property impacts, may be more important in determining impact on public health. The commission does not see any connection in SB 766 between BACT and the discretion of the commission to prescribe the appropriate health effects review. TCAA, §382.0519(c) does not allow the commission to issue VERPs to facilities which are not protective of public health and physical property. This provision was based, in part, on the authority that the commission has in the NSR permitting program under TCAA, §382.0518 to do a health effects review. In both cases, the discretion is left to the commission to determine the appropriate level of health effects review that is needed. Concerning the specific comment, the commission agrees that monitoring showing no adverse impacts could be an appropriate mechanism for allowing an abbreviated health effects review.

Two individuals commented that the commission should study the effects, or the cumulative effects of grandfathered facilities. SEED commented that the commission should require a strict, cumulative health effects review and that simply reducing emissions is not the same as ensuring that public health is protected. SEED added that a health effects review should include a study of the cumulative impacts of various pollutants emitted by the plant seeking a permit, as well as those from surrounding plants, and that it is the obligation of the commission to consider these cumulative effects and ensure that emissions are reduced to levels demonstrated to be safe prior to granting a VERP. TCE commented that a health effects review should include an analysis of cumulative impacts from multiple sources and chemicals that contribute to background levels. One individual commented that the health effects review should include a study of secondary sources, and that the commission should publish the results.

The commission has made no changes in response to these comments. If an applicant proposes an allowable emission rate higher than the highest rate reported over the previous three years, the commission's health effects review procedures could result in plant-wide modeling. However, to require such an extensive analysis for every VERP would be inappropriate, especially when actual reductions are obtained. The commission believes that it will rarely, if ever, be appropriate to require plant-wide, or area-wide modeling as a requirement for obtaining a VERP. The VERP program is intended to permit individual grandfathered facilities. The goal of the commission through the VERP program is to obtain reductions in emissions from those facilities. The commission believes that computer air dispersion modeling should be a tool that is used generally for predicting impacts from new or modified facilities. When there are actual reductions from existing, grandfathered facilities, the off-property impacts will be reduced when compared to historic levels. Therefore, the commission believes that its proposal for health effects review, which varies in scope depending on whether or not actual reductions occur, will protect public health.

EDF commented that the commission should adopt the minority report of the CARE committee on health effects review. EDF also noted that the proposed preamble concerning health effects review gives the impression that the environmental representatives voted with the industry majority on when to have abbreviated health impact reviews, and that it ought to be corrected to accurately reflect how the committee split on this issue. In addition, the commenter stated that the use of the highest actual emissions in a three-year period as a trigger mechanism rewards high-polluting companies and companies with upsets, and that the commission's use of the highest level of pollution for any of the baselines may result in this grandfathered program resulting in increased emissions of pollution over the average for normal levels.

The commission did not intend to mischaracterize the opinion of the environmental representatives on the CARE Committee and has revised the preamble to reflect the existence of a minority report. The minority report mentioned health effects several times. It stated that medium and large grandfathered facilities that are at or close to BACT emission limits, have demonstrated good compliance history, and for which there is no record of citizen complaints in the area may obtain a simplified standard permit and recommended that the commission should retain the option to require a health effects review as appropriate. The report also contained a recommendation for a flexible permit and stated that the commission should conduct appropriate health effects modeling based on baseline emissions and projected decreases, taking into consideration the type of facility and emissions profile. The report also contained a statement that the commission must require cumulative health impact analysis at a site when granting permits where large quantities of toxic emissions are evident, or complaints from neighbors have occurred, and that the commission should give special attention to areas of concentrated industrial activity and conduct monitoring and modeling for cumulative impacts in response to citizen health concerns.

The commission believes that the criteria for conducting health effects review discussed in the preamble are largely consistent with the recommendations of the minority report, the major exceptions being: that the minority report seems to base the level of health effects review on whether or not BACT is used, and the report contains a recommendation for cumulative health impacts review. As stated previously, the commission believes that the primary consideration in determining the level of health effects review is reductions in emissions, although BACT would receive consideration.

The commission believes that using the highest actual emissions over the previous three years as a baseline for triggering an abbreviated health effects review is appropriate. One of the goals of the VERP program is to obtain reductions in actual emissions from the 1997 level. Using a three-year period as the trigger, instead of simply using the 1997 level, eliminates the argument that any given year is not representative of the emissions of a facility, and should provide a representative rate from which to measure reductions. Since this approach should result in reductions, the commission believes that using the highest actual rate over any of the previous three years as an abbreviated health effects review trigger would not result in increased emissions over normal levels.

The EPA commented that it understands §116.811(1) to include protection of the NAAQS and that the rule ensures that no VERP or PERC will cause or contribute to ambient air concentration of a pollutant in excess of a NAAQS and that it will be consistent with any SIP and associated control strategy which ensures the attainment and maintenance of the NAAQS.

Section 116.811(1) provides that emissions from grandfathered facilities will comply with all rules and regulations of the commission. That includes regulations which are intended to ensure compliance with the NAAQS.

EPE supported the abbreviated health effects review, stating that no benefit would be gained from requiring a full health effects review at facilities with no demonstrated adverse impacts, and that a full review would discourage participation in the VERP program. BP Amoco commented that an abbreviated health effects review is appropriate in most cases, considering that the facilities are existing, rather than new sources. BMOH supported the concept of a limited health effects review for grandfathered facilities unless there are documented confirmed health effects from the facility at the emission levels proposed in the permit. GPM commented that the proposed requirement for a health effects review if a facility increases emissions and/or if controls do not meet current BACT is inconsistent with the language of SB 766 and unmandated by any other statute.

TIP commented that no health effects review should be required if a facility has already implemented BACT. Mobil commented that if an applicant has already installed BACT, it will not affect off-site receptors, or has previously reduced emissions, then the commission should be able to accept an abbreviated health effects review. TIP commented that a reduced emission rate should not be the only trigger for an abbreviated health effects review, and that the commission should consider that these units are existing, rather than new, sources. Therefore, the commission should also consider: 1) past reductions in actual emissions since 1971; 2) proximity to the nearest off-property receptor; and 3) monitoring data which demonstrates no off-property impacts. TxOGA commented that the commission should expand the proposed guidelines for automatic qualification for abbreviated health effects review of VERP applications to encourage voluntary streamlined permitting of grandfathered facilities and not impose burdensome special requirements. TxOGA added that granting an automatic health effects review only to those facilities that decrease emissions is an unnecessarily stringent application of commission discretion, since the sources volunteering for permits have been operating for many years. TxOGA recommended the following guidelines for determining an automatic abbreviated health effects review: 1) no emissions increases relative to the highest emission rate for the last three years; 2) sources which are or will use BACT or MACT; and 3) sources which utilize adequate controls required by the VERP program, but still have emission increases for some contaminants related to operation of those controls.

Similarly, GPM supported an abbreviated health affects review provided that the commission takes into account the following factors: 1) no health effects review should be required if BACT or VERP controls are proposed; 2) actual reductions from 1991 to the present should be considered (companies need the opportunity to demonstrate that the last three years is not the best basis for estimating grandfathered emission rates); and 3) proximity to the nearest off-site receptors. Coastal and BP Amoco mirrored GPM, but commented instead that reductions made from 1971 to the present should be considered. Coastal also commented that the commission should perform an abbreviated health effects review on sources which utilize adequate controls required by the VERP program, but still have emission increases for some contaminants related to operation of those controls. Coastal and BP Amoco suggested considering any monitoring data which can demonstrate that there are no adverse impacts.

TCAA, §382.0519(c) does not allow the commission to issue VERPs to facilities which are not protective of public health and physical property. The commission agrees that an abbreviated health effects review can be used to meet this requirement in some, perhaps even most, instances when the criteria stated previously in this analysis of testimony and in this adoption preamble are considered, especially when actual reductions are achieved. Similarly, it is not appropriate to use BACT as the sole factor to determine what level of health effects review should be performed. Other factors, especially the amount and type of emissions, the location of off-property receptors, and compliance history relative to off-property impacts, may be more important in determining impact on public health. However, the commission does not believe that the lack of documentation of adverse impacts, alone, is adequate reason to allow an abbreviated health effects review. The commission does not see any inconsistency with SB 766 by requiring a health effects review. In fact, §382.0519(c) clearly mandates that a VERP that will contravene protection of public health and physical property cannot be granted. This provision was based, in part, on the authority that the commission has in the NSR permitting program under TCAA, §382.0518 to do a health effects review. In both cases, the discretion is left to the commission to determine the appropriate level of health effects review that is needed. The commission believes that the only automatic mechanism for triggering an abbreviated health effects review is a reduction in actual emissions. Actual reductions in emissions is an important factor in improving air quality, and the commission feels that it is appropriate to automatically grant an abbreviated health effects review based upon emission reductions. However, considering any reduction made since 1971 when determining the appropriate level of health effects review may rarely be appropriate. One of the goals of the VERP program is to obtain reductions in actual emissions from the 1997 level. The commission believes that using the highest actual emissions over the previous three years as a baseline for triggering an abbreviated health effects review will result in a reasonable representation of recent actual emissions from a facility. The commission disagrees that failure to expand the guidelines for abbreviated health effects reviews is a burdensome special requirement, nor is it an unnecessarily stringent application of commission discretion. The commission is under no obligation to provide any automatic factors. Because an automatically abbreviated health effects review is allowed for what the commission considers to be the most important factor, actual reductions, it does not mean that it is burdensome to provide other factors, which, when considered together, could result in an abbreviated health effects review. Since grandfathered facilities have been operating for many years, streamlined permitting of grandfathered facilities and an abbreviated health effects review will often be appropriate when considering the previously listed factors, including the automatic factor.

TxOGA and Coastal commented that it is not clear what an "abbreviated health effects review" would be. They do not believe that the current health effects review flowchart is a suitable applicability method, and requested the commission to advise the regulated community what it proposes to do in making such a review. BMOH commented that further guidance should be proposed to identify the level of the abbreviated health effects review for grandfathered facilities, and that the term "abbreviated" is not specified in the rule or the proposed preamble in a manner which would apprise applicants of its meaning.

An abbreviated health effects review would be the minimum review required for the reviewing engineer to determine that the public's health and property will be protected. The minimum health effects review that the commission would perform would be to determine the amount and type of emissions, the location of the nearest off-property receptor, and to consider any compliance history relevant to off-property impacts.

One individual commented that the commission should require annual emission testing for PM_{10}, $PM_{2.5}$, nitrogen oxides (NO_x), CO, volatile organic compounds (VOC), Mercury, and Selenium.

The commission has made no changes in response to this comment. However the commission notes that when necessary to demonstrate compliance with the permit, a VERP permit will contain conditions for testing these and other air contaminants.

SC commented that the commission should be strict with the application of §116.811(2) because of the uncertainties of relying on emissions calculations and estimates. The EPA commented that §116.811(2) should more clearly specify when emission tests are required or explain how it is adequate to assure compliance. It noted that the commission should also address whether this applies to federal requirements, and if so, the source must perform testing pursuant to EPA approved methods and procedures.

The language in §116.811(2) is consistent with the language in §116.111(2)(B), which allows the commission to require measurement of emissions for regular NSR permits, and §116.711(2), which allows the commission to require measurement of emissions for flexible permits. In short, these provisions allow the commission to require testing, when appropriate, to determine compliance with the issued permit. For example, testing might be required to verify emission factors used, or the efficiency of a control device when there is some doubt as to their accuracy. These determinations are made, as needed, and the commission disagrees that more specificity is needed to clarify when these longstanding provisions are required, or how they are adequate to assure compliance. These provisions have no effect on any other state or federal requirements, except that they will be as consistent as possible with the other state or federal requirements, as applicable. The commission may not issue any permit which is not demonstrated to comply with state or federal requirements.

TIP and BP Amoco commented that the commission should provide flexibility to applicants to measure emissions via portable analyzers or to calculate emissions if some known process variable is monitored. Section 116.811(2) should in no way be construed to imply that continuous emissions monitoring will be required for a voluntary permit. TxOGA, GPM, and Coastal added that the commission should clarify proposed VERP requirements for measurement of emissions to demonstrate compliance with applicable federal standards, because §116.811(2) could be misconstrued to mean that continuous emission monitors would be required for VERP authorization, which would far exceed the intent of the legislature.

The commission agrees that §116.811(2) does not require, in and of itself, continuous emissions monitoring, and does provide the flexibility for the commission to require other forms of emissions measurement, such as portable analyzers or emission calculations. For clarity, the commission has added the examples that the commenters mentioned to §116.811(2).

Coastal added that Title V monitoring requirements should be considered adequate for the VERP program.

The commission has made no changes in response to this comment. The commission agrees that Title V monitoring requirements would be adequate for the VERP program, if they are required for the facility and if they demonstrate compliance with the VERP permit. Further, it does not intend to require conflicting or duplicative requirements for measurement of emissions through the air permitting program. The commission believes that §116.811(2) gives the commission the ability to require measurement consistent with ten-year old BACT or GACT and that Title V monitoring requirements would be at least as stringent as those requirements.

Representatives Maxey, Burnam, Dukes, McClendon, and Zbranek recommended that the commission designate the entire East Texas Region (as defined in Senate Bill 7) a near-nonattainment area due to the specific impact that the designation might have on public health and attainment of the NAAQS (specifically resulting from the transport of ozone) and on the use of PERCs within an airshed.

The commission has made no changes in response to this comment. In the development of this provision, the commission considered a number of factors. The list of counties considered near-nonattainment was derived from the cities listed in Article VI, §13, of the commission's appropriation in House Bill 1, 76th Legislature. That section appropriates funding for air quality planning in near-nonattainment areas, defined as Austin, Corpus Christi, Longview-Tyler-Marshall, San Antonio, and Victoria. The counties listed in the adopted rules correspond to these cities. The commission believes that it is appropriate to implement the near-nonattainment area provisions in a manner that is consistent with the Appropriations Act. The commission chose a narrow approach because it was hesitant to designate any specific county as near-nonattainment without scientific evidence. While pollutants from specific counties may contribute to ozone nonattainment, through transport, the specific counties themselves may or may not be near-nonattainment. In the future, the EPA might tend to designate a nonattainment area as broadly as the near-nonattainment area had previously been designated. If the commission designated the entire East Texas Region as near-nonattainment, and the EPA subsequently designated the entire region as nonattainment, many counties in the East Texas Region could suffer the economic consequences of being designated nonattainment without any scientific evidence indicating they specifically are in violation of the NAAQS. Second, a review of the data regarding grandfathered sources showed that designating the entire East Texas Region to be near-nonattainment, solely for the purpose of grandfathered permitting, would have little, if any, positive environmental impact. There are several reasons for this. When considering the largest sources, statewide, which represent 90% of grandfathered emissions, 18% are located in the attainment areas of the East Texas Region. Excluding ALCOA, who is not expected to be affected by the designation of "near-nonattainment," 22% of grandfathered emissions from the largest sources are in that region. Most of the largest, non-electric generating facility sources identified in the East Texas Region are oil and gas production facilities or paper production facilities. When considering the aggregate of emission units located at these types of sources, it is expected that the percentage difference in reductions resulting from ten-year old BACT or GACT would be small. As a result, only 3.0% of the largest sources statewide, representing approximately 5.0% of emissions, would be significantly affected by expanding the designation of "near-nonattainment area" to the entire East Texas Region. If ten-year old BACT could achieve reductions of 50% from those sources and GACT could achieve reductions of 90%, the potential impact on statewide reductions from the largest sources would still be, at the most, 2.0%. Therefore, analysis shows that based on the number and type of industry in the East Texas Region, there is little difference between the results of applying either control technology allowed under the VERP program. Although the commission believes that reductions in the East Texas Region are necessary and important to future attainment strategies, designating the entire region "near-nonattainment" does not seem to be warranted in light of the potential economic impact on the region.

GHASP and TCEA commented that the commission should define nonattainment area and near-nonattainment area broadly, with TCEA and NFN adding that the area should include contributing counties so that the toughest possible standards will be applied to as many grandfathered plants as possible. SC commented that the VERP program should get maximum reductions in the eastern airshed, and PC commented that the commission should define the area in which GACT applies as the entire 60-county region, and that at the very least, the definition needs to be broadened to include those counties that affect nonattainment counties, e.g., Ellis County affects Dallas. PC added that the commission cannot argue logically or legally that transport is limited to an area of four or eight counties in one portion of its rules while arguing that it is appropriate to set up a credit trading scheme for pollution in another section of the same rules. PC noted that considering core airsheds only limits the comparable plants to be considered for GACT, as most of the newer plants tend to be in areas outside the core urban areas; and that GACT needs to be tough enough to result in real reductions. TCE and SEED commented that to expand the number of variables for evaluating the most effective control strategy, the area for GACT determination should include the entire airshed, or maybe the entire region as defined in SB 7.

EDF commented that the commission should consider the entire eastern region (as defined in SB 7) plus El Paso County to be the region where GACT would be applied, noting that emissions from facilities in this region impact air quality in attainment, near-nonattainment, and nonattainment areas downwind. In addition, EDF commented that all counties in potential nonattainment areas which have violated the eight-hour standard should be included in the list of nonattainment counties. The current proposal is unfair to core urban counties and favors economic development in suburban counties, which often have the highest levels of ozone in a region and are significant contributors to the regions air problems. The commenter stated that the commission must reconcile the discrepancy between the region where GACT applies and the region where PERCs can be generated. Allowing PERCs to be generated in a broader region reflects an understanding that emissions reductions in another part of an airshed have the potential to prevent a comparable amount of pollution that would be necessary to comply with a VERP. On the other hand, the proposal to very narrowly define where GACT applies suggests that the commission sees little benefit in requiring GACT controls in counties upwind of nonattainment and near-nonattainment areas. The commenter suggested that the commission either expand the region where GACT applies, or limit the generation of PERCs to the same county or nonattainment area in which an applicant seeks a VERP.

As stated in a related response, the commission has determined that broadening the area where GACT could apply would have little environmental benefit in nonattainment counties when considered solely for the purpose of the VERP program, since few large grandfathered sources would be affected. The commission is not making a determination about whether ozone transported from the attainment counties in the eastern region of Texas impacts the nonattainment areas. Rather, the decision to limit the counties where GACT applies was made entirely within the context of the VERP program.

For that same reason, the commission does not believe that there is a need to reconcile the discrepancy between the region where GACT applies and the region where PERCs can be generated. If the newer plants are located outside the core urban areas and emissions from these areas impact ozone levels in the core urban areas, the commission believes that it makes sense for PERC reductions to be made at these newer facilities if the required reductions cannot be made at the grandfathered facilities in the core counties.

TCGA commented that §116.811(3)(B) seems to require a higher level of controls for businesses in the listed counties, on the basis that these counties are near-nonattainment. This seems to apply to any type of pollutant regardless of whether the area is near-nonattainment for that type of pollutant. For example, facilities emitting only particulate matter could be required to install a higher level of controls in Nueces County, even though particulate matter is not a pollutant of concern in this area.

The commission believes that the Legislature intended the term "near-nonattainment" in TCAA, §382.0519 to apply to NAAQS on a pollutant-by-pollutant basis. Therefore, since the listed counties are not considered to be near-nonattainment for particulate matter, §116.811(3)(B) has been amended to clarify that GACT might apply in the listed counties to grandfathered facilities which emit VOC or NO_x.

TxOGA and TIP supported the concept of listing specific counties in the regulation in which GACT may be required instead of defining near-nonattainment area. ATINGP added that by listing the counties in which GACT may be used, the commission has eliminated confusion and controversy. The association supports the listing of the following counties as areas where GACT may apply: Bexar, Gregg, Harrison, Nueces, Smith, Travis, and Victoria.

As it was proposed, the adopted rule lists the counties in which GACT applies.

Representatives Maxey, Burnam, Dukes, McClendon, and Zbranek recommended that the commission set limits on the length of time allowed for installation of control equipment, and that if a timeline is exceeded, the affected facility should cease operation, unless the timeline is extended by the commission for extraordinary situations.

The commission agrees that timely installation of control equipment is important to achieving the goals of SB 766. The current practice of the commission is to define timelines for installation of control equipment on a case-by-case basis through permit conditions, when a permit covering existing facilities is issued, and there is no immediate danger to public health. Typically, an existing facility is allowed no more than 18 months to install control equipment. However, in some cases, such as when an entire site is permitted under a flexible permit, applicants are allowed as long as ten years to install control equipment on existing facilities if it would prove financially impracticable to add controls to all facilities at once, the public health is protected, and controls are added annually. If a timeline is exceeded, the commission implements enforcement procedures. However, it is rarely necessary to elevate enforcement to the level of shutting down a facility. To encourage implementation of controls as soon as possible, the commission does not believe it is appropriate to place specific timelines in the rules, but would rather address the issue on a case-by-case basis in the permit.

Representatives Maxey, Burnam, Dukes, McClendon, and Zbranek recommended that the commission include a condition in the rules that would require those facilities that use a less stringent control requirement due to "the age and useful life of the facility" to cease operation once the projected limit on useful life is reached. This is because the considering the age and useful life of the facility would prove problematic to the agency when making control technology determinations. As an alternative that would allow continued operation of a facility, the commission should allow PERCs to be used if a facility continued to operate beyond its projected remaining useful life.

No changes were made in response to these comments. The commission recognizes that the consideration of the age and useful life of a facility will complicate control technology determinations, and agrees that permit conditions should limit, on a case-by-case basis, the continued operation of a facility beyond its projected remaining useful life. The commission believes it is appropriate to do this on a case-by-case basis through permit conditions rather than adding it to the rules. This approach will allow the commission to make determinations that are specific to the permit, and could include shorter or longer time frames, as necessary. The commission also believes that flexibility should be provided if a facility continues to operate beyond its projected remaining useful life. One option for flexibility would be to require the controls that would be required for a new or modified facility at the end of the projected remaining useful life. However, the commission does not believe that PERCs could be used to control emissions at the end of the projected remaining useful life, since an owner or operator may only seek authorization to use PERCs at the time of initial application for a VERP.

EDF commented that the commission should include special permit conditions if a VERP contains control methods less stringent than BACT because the applicant claimed the facility had only a limited remaining useful life. The facility should be required to cease operation at the end of the projected remaining useful life, or: 1) install the most up-to-date BACT prior to continuing operation; and 2) retire an amount of emission reduction credits equal to the cumulative difference in emissions between BACT at the time the VERP was issued and the less stringent GACT standard that was applied due to claims of a limited remaining useful life.

The commission agrees that permit conditions should limit, on a case-by-case basis, the continued operation of a facility beyond its projected remaining useful life. To continue operation, the commission agrees that the most appropriate approach would be to require the level of controls that would be required for a new or modified facility at the end of the projected remaining useful life. However, as previously noted, the commission does not believe that PERCs could be used to control emissions at the end of the projected remaining useful life, since an owner or operator may only seek authorization to use PERCs at the time of initial application for a VERP.

TCEA commented that when analyzing cost/benefit, the commission should include offsets for health care costs.

If the commenter was referring to the upper limit specified for GACT, the commission will make the determination compared with the cost of controls per ton of emissions reduced. The commission will not consider health care costs, since the long-accepted method of analyzing the cost/benefit of controls is to compare the cost of controls with the amount of emissions reduced. The commission may not issue a VERP which is not protective of public health.

Nine individuals commented that the commission should require BACT instead of VERP controls. TCEA commented that BACT should be implemented to minimize pollutants in all grandfathered facilities, as well as for all other facilities. Two individuals commented that the commission should require more stringent controls in nonattainment or near-nonattainment areas, and SC commented that the commission should probably require lowest achievable emission rate in nonattainment areas.

TCAA, §382.0519(b) allows grandfathered facilities to use either ten-year old BACT or GACT. Therefore, the commission has made no changes in response to this comment.

GHASP commented that the commission should define GACT stringently. Similarly, TCEA, and NFN commented that GACT should be stringent enough to result in reductions approaching 50%. MCA commented that the strictest allowable reductions on volunteering plants are necessary. If BACT is not used, GACT must result in real reductions. Plants must show real reductions in order to qualify for a permit.

The commission has made no changes in response to these comments. TCAA, §382.0519 does not specify the percentage of emission reductions in order to qualify for a VERP. Rather, the level of controls that must be achieved in order to qualify for a permit is specified. TCAA, §382.0519 has defined GACT as a control technology that the commission has found to be generally achievable for facilities in the area of the same type, considering the age and remaining useful life of the facility. Before age and remaining useful life are considered, the commission interprets GACT to be equivalent to the first-tier of BACT, which is the level of control technology used by a representative number of identical facilities.

One individual and PC commented that the commission should define the term "good faith effort." Another individual commented that the commission should remove the terms "good faith effort," "generally achievable for facilities in that area," and "remaining useful life of the facility" from §116.811 because they are arbitrary and capricious.

The commission has made no changes in response to these comments. The commission's use of these terms is consistent with TCAA, §382.0519(b) and §382.05193(a)(1). Further, the commission declines to define "good faith effort," because of its circumstantial nature. Since this is a term used to determine eligibility for use of PERCs in lieu of VERP controls, the commission believes that each case should be determined on its own merit.

The EPA commented that the commission should address whether it is appropriate to include enforceable restrictions on operation if a facility, at the time it applies for a VERP, operates at less than its design capacity. Without restrictions, the facility could exceed its current level of emissions if it later increased its operation, even with the application of ten-year old BACT or GACT.

The commission agrees that it would be possible for a facility to exceed its current level of emissions even with application of VERP controls. For example, that situation could occur without triggering a modification (which would result in permitting under Chapter 116, Subchapter B) if a facility is already using the required controls and is emitting at a rate below a proven, historical grandfathered emission rate. Section 116.814 allows for general and special conditions to be placed in VERPs. These conditions will be used to establish allowable emission rates and to ensure compliance with VERP requirements and the protection of public health. Therefore, the commission agrees that it is appropriate to include enforceable conditions in a permit, regardless of whether a facility is operating at its design capacity.

The EPA commented that control requirements in §116.811 appear to only apply at initial issuance of VERPs, and that if modifications are made, the BACT in effect at that time would apply.

The commission agrees with the EPA's understanding.

EPE commented that the commission should require ten-year old BACT for all grandfathered facilities regardless of location, with GACT eliminated entirely. The commenter further stated that requiring more stringent controls in nonattainment and near-nonattainment areas will have the undesired affect of penalizing facilities that elect to obtain a VERP. If the commission retains GACT, it should be clearly defined as first-tier BACT, so that it will not be a moving target, and to provide assurance that GACT requirements remain reasonable.

The commission has made no changes in response to these comments. TCAA, §382.0519(b)(2) requires VERP applicants to use the more stringent of ten-year old BACT or GACT in nonattainment and near-nonattainment areas. Before age and remaining useful life are considered, the commission interprets GACT to be equivalent to the first tier of BACT, which is the level of control technology used by a representative number of identical facilities.

EDF commented that defaulting to first-tier BACT as a working definition of GACT is appropriate.

The commission agrees that first-tier BACT is the most appropriate starting point for determining GACT. The first tier of BACT is the level of control technology used by a representative number of identical facilities. Before age and remaining useful life are considered, this is almost identical with the definition of GACT provided in TCAA, §382.0519(b)(2)(B).

One individual asked how BACT is defined. BMOH commented that ten-year old BACT is a more appropriate starting point for determining GACT, because it avoids the presumption that current BACT is GACT, and ensures that the factors applied to any potential additional controls are considered in light of what is generally achievable. When there has not been a previous determination of ten-year old BACT, the generally achievable standard would ensure that the applicant would be able to evaluate controls in place at other sources within the area in making the decision whether to go forward in the filing of a VERP application. The commission's approach to define first-tier BACT as the starting point does not establish why the final control selection is generally achievable. TxOGA and Coastal commented that ten-year old BACT should be the starting point for discussions as to what controls are generally achievable with first-tier BACT as the ceiling and that GACT should be interpreted to involve widespread use of certain control technology for similar facilities in a specific area, and not individual or isolated applications. BP Amoco and TIP also commented that the term "generally achievable" should imply widespread use in an area, not simply individual cases of control technology applicability. TxOGA commented that statewide determinations of GACT for the VERP program should not be driven by control strategies developed for nonattainment areas; such control strategies should remain focused on the nonattainment areas themselves.

The first tier of BACT is the level of control technology used by a representative number of identical facilities, not isolated applications. Before age and remaining useful life are considered, this is almost identical with the definition of GACT provided in TCAA, §382.0519(b)(2)(B). Therefore, the commission believes that it is the most appropriate starting point for determining GACT. The commission agrees that first-tier BACT would be the ceiling for GACT since age and remaining useful life, as well as the controls achieved by other facilities in the area, might then be considered. The commission agrees that attainment areas should not necessarily be considered the same as a nonattainment area. Therefore, it could be argued that SIP controls required for nonattainment areas might not be appropriate where GACT applies in attainment counties.

TxOGA and TIP commented that the commission should adequately consider facility age and remaining useful life in determining GACT.

The commission recognizes that consideration of facility age and remaining useful life is part of determining GACT. It will carefully consider age and remaining useful life and will use permit conditions to limit the continued operation of a facility beyond its projected remaining useful life.

TxOGA and Coastal commented that the commission should reconsider its stated presumption that GACT is between ten-year old BACT and BACT in stringency. The commenters stated that the legislature recognized that GACT may be less stringent than ten-year old BACT in requiring that the more stringent of the two be used in nonattainment areas. GACT is required as the control technology only in the instances when it is more stringent than ten-year old BACT. TIP also commented that in many cases GACT may be less than ten-year old BACT.

The commission believes, that in most, if not all, cases, GACT will be more stringent than ten-year old BACT. Before consideration of age and remaining useful life, the definition of GACT provided in TCAA, §382.0519(b)(2)(B) is almost identical to the first tier of BACT. The commission has revised the preamble to clarify that GACT will, in most cases, be more stringent than ten-year old BACT, and removed the statement that GACT is between ten-year old BACT and BACT in stringency.

BP Amoco commented that in nonattainment areas, the commission should defer to the SIP strategy to define necessary controls rather than using the VERP program to drive/define control requirements. New SIP rules will be promulgated in late 2000.

The commission agrees that, if known, future SIP control requirements should be considered when determining VERP control levels, to the extent that the SIP requirements would be ten-year old BACT or GACT.

TxOGA and Coastal commented that the commission should reconsider its presumption that GACT could cost up to $10,000 per ton of emission reductions, and that the commission appears to be taking the position that any controls which do not exceed that cost would be reasonable. This cost factor is commonly applied to BACT determinations and is not reasonable for application to facilities that will already be 30-plus years old at the time the expenditures are required. The commenters stated that the commission presumption is not consistent with the legislative intent that age and remaining useful life of the facility be considered. Coastal added that the cost of retrofitting grandfathered facilities, in view of their expected life and environmental benefits, must be considered when evaluating controls. Mobil commented that the commission has not complied with the requirements of the statute in development of GACT. The preamble states that GACT is presumed to lie between ten-year old BACT and BACT in stringency and sets an arbitrary value for emission reduction costs up to $10,000 per ton. The statute states that the age and remaining useful life of a facility should be considered in determining GACT. BP Amoco and TIP commented that $10,000 per ton for GACT is not reasonable, as this amount is typically reserved for BACT, if appropriate. TIP added that equating the cost of GACT with BACT ignores the age and remaining useful life of the facility.

The commission believes that in many instances, the cost of retrofitting an existing facility could be as expensive as applying BACT to a new facility. In order to establish an estimate of program costs in the proposed preamble, the commission used the $10,000 per ton limit as a limit typically considered in current BACT review, depending on the type of facility and pollutant to be controlled. In actuality, the cost of retrofitting an existing facility could be lower or, in some cases, higher than $10,000 per ton, annualized. The commission will consider the age and remaining useful life of a facility when determining GACT, including the consideration of cost, as appropriate.

Mobil requested that the commission expressly provide for phase-in of control requirements consistent with other federal or state regulatory requirements. TxOGA and Coastal commented that clarification is necessary to ensure that phase-in of control requirements is not considered a deferral under §116.816. The commenter provided suggested language to be added to §116.811(3)(C). BP Amoco and TIP also commented that language should be added to distinguish between deferrals and phase-in of controls.

The commission agrees that deferral of control requirements under §116.816 is different than phase-in of VERP controls. As previously noted with regard to timelines for installation of controls, the commission recommends phase-in of controls on a case-by-case basis in permit conditions. While federal or state requirements may be one of the reasons that phase-in of controls would be allowed, there may be other reasons for allowing phase-in of controls. Providing an exhaustive list of other reasons in the rule would be unintentionally limiting; therefore, the rule language has not been revised.

PC commented in support of the commission's position that nothing in the legislation overrules the applicant's responsibility to meet federal requirements, e.g., NSPS, NESHAPs, maximum available control technology, or SIP requirements.

The commission agrees, and retained the provisions regarding federal requirements in the adoption.

The EPA commented that the provisions of §116.811(4), (8), (9), and (11) apply to new or modified sources and do not appear to apply to grandfathered sources, but that these provisions may apply to facilities which use PERCs. The commenter stated that these provisions must also ensure that a facility applying for a PERC continues to meet all applicable federal provisions. In addition, EPA stated that the commission must add the phrase, "applicable requirements of the Texas SIP, including such provisions as reasonably available control technology." A separate EPA commenter added that §116.811 should be amended to state that the amount of VERP allowances should not exceed the 1990 Emissions Inventory (EI) or the emissions reported in any Rate-of-Progress (ROP) SIP submitted for an ozone nonattainment area.

The commission believes that it is appropriate to include the listed federal provisions, as proposed, because it is conceivable that a VERP control requirement could trigger federal review, e.g., a flare is considered GACT and the resulting products of combustion exceed federal trigger levels. While it is unlikely for this to occur, since the benefit of flaring would conceivably outweigh any increase in products of combustion, the commission believes that listing the federal requirements ensures that they will be complied with, if triggered. The commission agrees that VERPs are only for unmodified facilities, but could also include new facilities, if that new facility is a required control device. The listed federal provisions apply to any VERP permit, including those that use PERCs. The commission does not believe that it "must add" a reference to the SIP regulations, since §116.811(1) requires compliance with all rules and regulations of the commission. Therefore, the rule was not revised.

Regarding VERP allowances (reductions), the commission did not propose the VERP program as a SIP submittal. Therefore, the commission cannot, in this adoption, commit the VERP reductions to the SIP. However, the commission may do so in a future SIP submittal or use a portion, or all, of the reductions in SIP attainment demonstration modeling. Therefore, the rule has not been amended to address VERP reductions as they relate to the EI or ROP.

B&P commented that the rules should state that a VERP cannot be used to authorize construction or operation of a new source or a modification of an existing source, rather than require grandfathered facilities to meet applicable nonattainment NSR and PSD requirements.

The commission agrees that VERPs should not be used to authorize construction or modifications. However, the commission has not modified the rules, as requested. Section 116.811(8) and (9) are intended only to require VERP applicants to comply with the existing rules for PSD and nonattainment permit review. The commission must verify compliance with state and federal rules before issuing permits.

TIP commented that §116.811(7) should be deleted. The commenter stated that the provision allowing the commission to require additional engineering data after VERP issuance is overly broad and would allow the commission to exceed its statutory authority.

The commission disagrees that §116.811(7) should be deleted or that it exceeds statutory authority. The provision is necessary to require and verify compliance with permit conditions. While it may not be appropriate to require performance demonstrations in most cases under the VERP program, the commission needs the ability to require performance demonstrations in such instances as implementation of unproven control technology, or where there is uncertainty with the emission factors used to determine emission rates.

The EPA commented that §116.811(7) should be more definite to ensure compliance using the appropriate testing, monitoring, and recordkeeping that the commission established in the permit after evaluating the permit application and considering relevant information on the operating and production parameters which affect the emissions. See 40 CFR 51.212(c).

Section 116.811(7) allows the commission to require and verify compliance with permit conditions. Performance demonstrations may vary from VERP to VERP, and it is inappropriate to include those details here. Therefore, §116.811(7) has not been revised in response to this comment.

GPM commented that requiring modeling will be very costly and will cause unnecessary delays. The commenter stated that the commission is required to expedite VERPs within two miles of certain sensitive receptors, and the inclusion of modeling will be counter to that directive. BP Amoco commented that modeling should not be required where permitting efforts result in reduction in emissions. TIP commented that the commission should further define when it may require modeling or monitoring under §116.811(10), as guidance has not been provided and that modeling or monitoring should not be required when the VERP has resulted in decreased emissions.

The commission agrees that no modeling will be required if a VERP results in emission reductions. An abbreviated health effects review would not require modeling. However, the commission believes that modeling is appropriate in certain instances and will consider the criteria included in the previous discussion, relating to the level of health effects review, when determining whether it is appropriate. The commission does not agree that modeling is an unnecessary delay to the extent that it would be appropriate to ensure the protection of off-property receptors, including the listed sensitive receptors within two miles. The cost of modeling may be mitigated, especially for small businesses, since commission staff can sometimes perform the appropriate modeling.

Representatives Maxey, Burnam, Dukes, McClendon, and Zbranek recommended that the commission require applicants to delineate, within the application, the actual emissions reductions projected under the VERP. EDF commented that §116.811(12) should be amended (and reflected in the PI-1V) to require applicants to include an estimate of emission reductions resulting from a VERP. This will facilitate public review of applications.

The rule, as proposed and adopted, allows the commission to require additional support information in the application form; therefore, no change is needed in response to this comment. The current NSR practice requires a table to be submitted with permit applications which identifies proposed emission rates on a unit-by-unit basis. This practice will continue under the VERP Program. Every VERP issued will have an allowable emission rate, which can be easily compared to the actual emission rates represented in the 1997 Grandfathered Sources Survey or to the EI. An allowable rate should be equivalent to the maximum actual emissions expected by an applicant after implementation of controls.

The CAP commented that the commission should offer suggestions on BACT, GACT, and ten-year old BACT for different types of facilities, and should be made available prior to the application deadlines to help small businesses mitigate the cost of submitting an application and the cost of hiring a consultant.

The commission currently maintains a list of ten-year old BACT and will make the list available to small businesses. As GACT determinations are made, the commission will similarly develop a list and make it available.

TIP commented that the commission should modify §116.811(12)(E) to clarify that an applicant may identify more than one date for the installation and operation of emission reduction projects. The commenter stated that such a change would clarify that a facility may phase-in emission controls if multiple changes are required.

The commission agrees that phasing-in of controls is often appropriate. If more than one facility is included in a VERP application, the commission assumes that multiple dates for installation of controls will be provided, on a facility-by-facility basis. Section 116.811(12)(E) is broad enough to allow this, and has not been revised. Further clarification will be provided as needed.

GPM commented that the commission should withdraw the 3,000-foot requirement from the rules, since imposing special requirements on grandfathered facilities within 3,000 feet of a school seems inconsistent with the goal of encouraging participation.

The proposed and adopted rules do not contain any requirements for grandfathered facilities within 3,000 feet of a school. When issuing a permit to construct or modify a facility, TCAA, §382.052 requires the commission to consider adverse effects at schools within 3,000 feet. However, Chapter 116, Subchapter H will not authorize new or modified facilities, so that requirement has not been included. TCAA, §382.0519(f) does require the commission to give priority to applications for facilities less than two miles from schools, daycare centers, hospitals, or nursing homes. This requirement was included in the proposed and adopted rule in §116.813(b).

EDF commented that PERCs should not be used to shift the burden of pollution exposures from one group to another, and that the alternative control measures should control the same pollutants as the facility in question emits. The commenter stated that PERCs should not be used to provide relief to the general population at the expense of continued toxic releases that affect a specific neighborhood. Failure to craft this program is likely to bring the state civil rights environmental justice lawsuits. One individual commented that the commission should not allow emission reduction credit programs or emission reduction credit trading programs. These programs ensure that environmental justice concerns will not be addressed, as some people will have emission reductions in their area, while others will be forced to breathe air which will harm their health. Two individuals, C&S, and MCA commented that the commission should not give emission reduction credits for phantom reductions. The same individuals and C&S added that the commission should not allow bait and switch reductions and that PERCs must result in quantifiable emission reductions with real penalties or retraction of the permit if the reductions fail to happen. MCA and LWV added that PERCs must result in quantifiable emission reductions before they qualify as conditions for issuance of a VERP, and that real penalties or retraction of the permit must occur if reductions fail to happen. LWV added that the commission should monitor PERCs.

TCAA, §382.05193(b) requires the commission to develop and implement a PERC program for facilities that have made a good faith effort to meet VERP controls, but cannot reduce the facility's emissions to the degree necessary to obtain a VERP. The commission agrees that emission reductions should be real, and in addition, should be enforceable, permanent, quantifiable, and surplus. These criteria are all contained in §116.812(c) and are used in the EPA's and commission's emission reduction credit trading programs. The commission also agrees that no particular population should be adversely impacted by the PERC program. The VERP program requires the commission to ensure that public health and physical property are protected, regardless of whether controls, PERCs, or deferrals are used to meet the VERP requirements. If there are no emission reductions at a facility, the commission will use the criteria mentioned previously for determining what level of health effects review should be performed. If the commission cannot verify that the emissions from the grandfathered facility are protective of public health, the commission will be unable to issue a VERP permit.

TCAA, §382.05193 and the adopted rules provide that PERCs must reduce net emissions from one or more sources in the state in an amount and type sufficient to prevent air pollution to a degree comparable to the amount of the reduction in the facility's emissions that would be necessary to meet the permit requirement. While it may not be appropriate in all cases for the reduction to be pollutant for pollutant, the commission interprets comparable to mean similar in amount and potential adverse impacts and that the reduction will have the same benefit for attainment of the NAAQS and is an air contaminant of similar environmental significance.

Two individuals, MCA, and LWV commented that the commission should require PERCs in the same airshed as the plant trying to get a permit.

The commission agrees, and has maintained this provision in the adopted rules.

One individual commented that the commission should not allow the purchase of autos to be used as a method of reducing emissions, because there is no way of knowing if the autos were actually being driven, or how much they were driven. The commenter stated that the commission should reduce emissions at the source. SC commented that the commission should certify that any automobiles used for PERCs are destroyed and that they are not piled up in a neighborhood with gasoline in the fuel tanks.

TCAA, §382.05193(c)(2) specifically provides that PERCs may be created by the purchase and destruction of high emission automobiles or other mobile sources. Therefore, the commission did not remove this option from the adopted rules. However, the rules require applicants to prove that these projects will result in real, quantifiable, and enforceable reductions. The commission believes that this will ensure the removal of operating vehicles, rather than those that are simply abandoned. The commission also believes that it has broad enough authority to ensure that places where automobiles are stored will not adversely impact neighborhoods.

PC asked how reductions used to create PERCs would be quantified and commented that the commission should use other states and federal credit programs for values, or have a hearing to establish values.

The commission will use emission factors, monitoring, or any other verifiable method for quantifying reductions and will review other state and federal programs as necessary.

PC asked how the commission would assure that there are real penalties if emission reductions do not occur, and commented that the commission should require annual reports and conduct random audits to assure that real reductions are occurring.

PERCs will be implemented through the VERP permit and the commission will utilize its well-established enforcement program to ensure that permit holders are complying with all conditions of the VERP. Reports and audits may be required as conditions of the permit, if appropriate.

PC asked how long will credits would have value, and commented that the commission should require credits to be used within the year, unless they are excess credits resulting from an early retirement or extra emission reductions. The program should operate for just ten years.

The commission has made no changes in response to this comment. The rules, as proposed and adopted, require the reductions used to create PERCs to be permanent. Additionally, once a PERC is used to meet the requirements for obtaining a VERP, it will be retired.

TRPC commented that the renewable power industry in Texas is expanding to meet the SB 7 renewables mandate, and that retail electric providers are becoming familiar with renewable power through their implementation of the SB 7 mandate. The TRPC agrees with the commission proposal that renewable power required under SB 7 is not eligible to be used in the PERC program. However, it will be easy for retail electric providers to procure additional output from renewables and to integrate it as a replacement for fossil-based power. The commenter stated that offsetting pollution for the remaining lifetime of a grandfathered facility through renewable power will require contracts whose length coincides with the useful life of the grandfathered facility, which is feasible since wind power projects have useful lives as great as 25 to 30 years. To help reduce the cost of power from renewables, the commission may certify renewable power as a pollution reduction technology eligible for exemption from state property taxes and eligible to use pollution abatement bonds issued by local governments. The commenter further stated that the commission has an interest in ensuring that renewable power, whether locally generated or imported from another region, actually offsets fossil-based generation within the airshed of the grandfathered facility, and that the commission should state in the rules that renewable power imported from other regions can be used to offset fossil-based generation that would otherwise serve the grandfathered facility. Finally, the commenter stated that the commission proposal is potentially problematic in this regard, since the commission would require a demonstration that the renewable power is displacing permitted generation from a specifically designated power plant in the same airshed. A more practicable approach to consider would be reducing overall power generation within the airshed and/or allowing the purchase and retirement of allowances issued under SB 7.

The commission will explore whether or not it has the authority to declare a renewable energy source, such as wind power, to be a pollution control device for the purposes of property tax exemptions and pollution abatement bonds. The commission would only do so if the wind power resulted in real, quantifiable, enforceable, surplus, and permanent reductions in emissions. The commission would allow renewable power imported from other regions to be used as PERCs, as long as it produces a verifiable reduction in emissions in the same airshed as the grandfathered facility is located, and meets other PERC criteria. The reduction would not have to come from the same power plant, but would have to come from the same airshed. The commission agrees that it might be possible to create a PERC by purchasing and retiring allowances created under SB 7 as long as they are not used to meet the requirements of that program. The commission did not adopt any of these concepts into the rules, since more exploration of these concepts is needed at this time.

PC commented that the commission should develop the PERC program to allow the use of renewable energy in an emissions credit trading scheme, and that the commission should adopt, by reference, the capacity factors developed by the Public Utility Commission to convert renewable capacity to energy for purposes of calculating avoided emissions. The commenter stated that allowing utilities to create emission reductions from permitted plants is unlikely to assure any real reductions, since the reductions would probably occur at peaking units, which are used infrequently. In order for the PERC program to result in real reductions, the rules should be modified to require permit reductions based on the last five years of actual emissions. PC stated that to allow the rules to work in a competitive electric industry, the commission should allow a retail electric provider to sell renewables to a grandfathered facility and assume that there will be a reduction per megawatt hour at the power plants in the area. Or, the commission could allow the retail electric provider to buy and retire NO_x allowances from the Senate Bill 7 emissions banking and trading program. The commenter stated that the commission can reduce the cost of renewable energy by declaring renewable plants to be pollution control devices, which would exempt owners from property taxes and allow them to qualify for pollution abatement bonds issued by local governmental units.

As previously stated, the commission believes that the concept of using renewable energy to create PERCs is worthy of additional exploration. At this time, the commission believes that it is premature to revise the rules to include renewable energy provisions. If appropriate, provisions can be implemented through guidance or future rulemaking.

SEED and TCE commented that the ratio of reductions should be consistent with federal standards or 1.2 to 1, and that for every credit of reduction, there must be a greater actual reduction.

The commission has made no changes in response to this comment. TCAA, §382.05193(c) requires a "comparable" reduction, and does not specify a ratio.

EDF commented that the rules fall short of encouraging smart use of PERCs by not clearly outlining what information is needed from industry seeking a PERC. The commenter further stated that the requirements for enforceability, permanency, etc., are the correct criteria, however, leaving the details to guidance documents makes it impossible to evaluate the adequacy of the PERC program. The rules also seem to not fully appreciate the complexity of making such determinations in a regulatory setting and the amount of resources needed by the agency to administer such a program.

Because the commission recognizes the complexity of the PERC program, the commission believes that it is only appropriate to capture the basic framework in the rules. The implementation procedures for this program will be very detailed and potentially fluid as the program develops. Further, the commission is gaining experience with some of the allowed projects for the first time. Therefore, the commission believes that it is premature to propose a high level of detail in the rules. As the PERC program is implemented, the commission will seek input from interested parties, at a minimum, through the public comment for issuance of individual VERPs.

The EPA commented that the commission should address how it will determine the baseline for crediting PERCs, and that the plan should be consistent with the approved plan for demonstrating attainment and maintenance of the NAAQS.

The commission addressed consistency with the NAAQS in both the proposed and adopted rules by requiring that PERCs be surplus to state or federal laws, regulations, and agreed orders. Therefore, the baseline for PERCs will be the actual emissions from the facility as adjusted by any applicable current state or federal laws, regulations, or agreed orders.

The EPA commented that §116.812(b)(3) could allow a source whose actual emissions are less than its permitted allowables to reduce its allowable emissions to its current actual emissions and credit the difference between the old and new allowable as a PERC, although there is no reduction in actual emissions. The commenter stated that this would have no environmental benefit and is inconsistent with §116.812(c)(5), which requires a real reduction in emissions. The EPA stated that the commission could clarify §116.812(b)(3) by appropriately cross-referencing §116.812(c)(5) and ensuring that §116.812(b)(3) does not supersede §116.812(c)(5).

All of the criteria in §116.812(c) apply to "any proposed PERC." Therefore, the rule has not been revised.

EPE commented that the commission should allow for the transfer and trading of PERCs between airsheds, as allowed in the commission's current banking and trading rules, in order to provide economic drivers and benefits to participating companies. The commenter also stated that the commission should allow all enforceable emission reductions, including allowables, to be eligible for PERCs to encourage participation in the VERP program.

The commission has made no changes in response to this comment. TCAA, §382.05193(f) provides that PERCs are not transferable. The commission interprets this to mean that they are not tradable. In addition, TCAA, §3822.05193(b) requires PERCs to be generated in the same airshed as the grandfathered facility being permitted. The commission disagrees that it is appropriate to use allowable emissions to create PERCs. The commission is not aware of any emission reduction credit program that recognizes allowable emissions, and further, believes that emission reductions should have actually occurred before credits can be generated.

EPE commented that the commission should clarify whether PERCs can involve any criteria pollutant or whether they must be in-kind, pollutant for pollutant, and that the PERC provisions should allow substitution, since the goal of the VERP program is to reduce pollutants.

The commission has made no changes in response to this comment. TCAA, §382.05193(c) and the adopted rules provide that PERCs must reduce net emissions from one or more sources in the state in an amount and type sufficient to prevent air pollution to a degree comparable to the amount of the reduction in the facility's emissions that would be necessary to meet the permit requirement. The commission believes that comparable means similar in amount and potential adverse impacts and that the reduction will have the same benefit for attainment of the NAAQS and is an air contaminant of similar environmental significance. Therefore, the commission believes that pollutant for pollutant reductions would be appropriate in most cases.

TIP supports the commission proposal to allow PERCs to offset emissions when GACT cannot be practically achieved. The commenter stated that facilities should be allowed to use PERCs for all emission reduction activities initiated after the proposal date of these rules, and that the commission should confirm that such emission reduction activities will be creditable to the facility under §116.812(a).

The commission encourages reductions as soon as possible and believes that it may be appropriate for any PERC created specifically for the purpose of obtaining a VERP to be used as long as the reductions are real, quantifiable, enforceable, surplus, and permanent.

TxOGA, Coastal, and Mobil commented that the commission should clarify that any legitimate emission reduction project may be used to generate PERCs. The commenters stated that a facility should be allowed to implement any emission reduction project that reduces net emissions of a type sufficient to prevent air pollution to a degree comparable to the amount of reduction that would be necessary to comply with §116.811(3). The proposed regulations appear to limit a facility to using only one of the legislatively listed projects for a PERC. TIP and GPM commented that reductions of emissions below the levels required in exemptions from permitting should be creditable for a VERP under §116.812, and that §116.812(b)(3) seems to limit PERCs to permitted facilities; therefore, language should be added to include exempted facilities or facilities permitted by rule.

The commission did not intend to limit PERC projects to those listed in the proposed rule. The statute does not limit the types of projects, and the commission has amended the rule to clarify this.

TIP and GPM commented that §116.812(a) should be rewritten. The term "excessive emissions" gives the impression of noncompliance. TIP added that if §116.812(a) is rewritten, the definition of excessive emissions in §116.16 should be eliminated. BMOH also commented that §116.811(3)(D)(iii) should be reworded to make the definition of excessive emissions unnecessary, because the definition is inflammatory and ultimately unnecessary, since it easily equated with unauthorized emissions. BMOH stated that the commission should also reword §116.812(a), similarly.

The commission agrees with suggested changes and has revised the rule accordingly.

BMOH commented that the commission should define the term "significantly," as used in §116.812(b)(3), so as to ensure that it is not to be equated with the term "significant" as it applies to 30 TAC Chapter 106.

The commission has made no changes in response to these comments. Since the commission did not propose a definition for this term, it feels that it is inappropriate to create a definition at adoption without specific input from interested parties. However, the commission agrees that the term "significantly" in §116.812(b)(3) should not be equated with the term "significant" as that term is used in the context of Chapter 106 (relating to Exemptions from Permitting), and will implement the provision accordingly.

BMOH commented that the commission should provide guidance and clarification of what the term "comparable" means. The commenter asked if the commission intends that area-wide modeling of emission reduction credits will be necessary to show that the PERCs are "sufficient to prevent air pollution to a degree comparable" to those that would otherwise be required under a VERP. BMOH felt that the term should mean similar in amount and potential adverse impacts.

The commission agrees that the term "comparable" should mean similar in amount and potential adverse impacts and would add that the reduction will have the same benefit for attainment of the NAAQS and is an air contaminant of similar environmental significance. The commission does not believe that area-wide modeling will be necessary to show that PERCs generate comparable emission reductions.

BMOH commented that the commission must grant PERCs if an applicant satisfies the conditions stated in the rules, as provided for by §382.05193(b). The commenter stated that the rule appears to provide some unspecified discretion to the commission to deny PERCs, and that if there are conditions under which PERCs will not be granted, this must be stated in the rule itself.

The commission will grant PERCs that meet all of the criteria established in the rule, including the requirement that comparable reductions must be real, quantifiable, enforceable, permanent, and surplus, and that the commission is able to verify that the emissions from the grandfathered facility are protective of public health and property, which is a condition of VERP issuance. Therefore, the commission has clarified §116.812(a) to alleviate the appearance of unspecified discretion.

B&P commented that the commission should revise the proposed definition of permanent in §116.812(c)(2) by removing the statement that permanent means unchanging, because an emission reduction could be permanent even though it changes (i.e., the emission reduction could increase).

The commission has made no changes in response to this comment. The commission would consider additional reductions from a project which generated a PERC to be a new reduction. Any reductions relied upon for a PERC would have to remain unchanged and permanent.

GHASP, TCEA, and NFN commented that the commission should give priority to the permitting of grandfathered facilities within two miles of schools, daycare centers, and nursing homes. NFN added that these facilities should receive the most careful scrutiny by staff. GHASP also commented that priority should be given to other centers where the population is known to be especially vulnerable to the effects of air pollution.

TCAA, §382.0519(f) requires prioritization of review of VERP applications located less than two miles from the outer perimeter of a school, daycare facility, hospital, or nursing home. The commission will scrutinize all applications.

TIP commented that the commission should give priority to grandfathered or formerly grandfathered facilities that have submitted applications that will result in substantial reductions in ozone precursors.

The review of VERP applications is a top commission priority. TCAA, §382.0519(f) requires prioritization of review of VERP applications located less than two miles from the outer perimeter of a school, daycare facility, hospital, or nursing home. The commission will consider the substantiality of reductions in ozone precursors among other factors when considering second-tier prioritization.

One individual commented that the commission should not allow deferrals, noting that it would allow people to be harmed by one pollutant while reducing another. The individual stated that if a grandfathered facility cannot meet the requirements of the VERP program, the commission has no business permitting it.

The commission has made no changes in response to this comment. Deferrals of certain air contaminants are specifically authorized by TCAA, §382.0519(e) if substantial reductions are made in emission of other air contaminants that meet commission priorities. One of the factors that the commission will consider when granting a deferral is the benefit to public health from the reduction of other specific air contaminants versus the deferral. In addition, the commission may not issue a VERP, including a VERP which contains a deferral, unless the public health is protected.

PC commented that the commission should define what constitutes economic hardship and technical impracticability. Without definition, technical impracticability becomes a loophole that could be an excuse for almost any plant to argue that it cannot clean up. The commenter stated that the rules should propose a ratio of reductions, such as 1.5 tons of reduction for every ton emitted, and that the rules should have a ten-year limit on deferrals to avoid creation of great-grandfathered plants. The EPA commented that deferral projects should have a time limit.

The commission declines to define economic hardship and technical impracticability because both are terms that are circumstantial in nature. Since this is a term used to determine eligibility for use of deferrals in lieu of VERP controls, the commission believes that each case should be determined on its own merit. Information concerning the annualized cost of controlling emissions will be an essential component of any application requesting a deferral. TCAA, §382.0519(e) and the adopted rules require substantial emission reductions of other air contaminants if reductions in certain specific air contaminants are to be deferred. The ratio of reduction is also circumstantial and will be based on commission priority to meet statewide air quality needs. The commission does not believe it is necessary to have a ten-year limit on deferrals, because anticipated state or federal regulations will, in all likelihood, require reductions in the emissions deferred in that time period.

TCE and SEED commented that they are concerned that the deferral provisions would allow ALCOA's Milam County facility to continue to emit 60,000 tons per year of sulfur dioxide (SO_2) that contributes to attainment problems in DFW. SEED and TCE also commented that the economic hardship provision for ALCOA is not warranted, given that it claims that $100 million in scrubbers would force it to close its doors when they have just recently purchased Reynolds Aluminum for $5.6 billion in cash.

TCAA, §382.0519(e) requires substantial emission reductions of other air contaminants if reductions in certain specific air contaminants are to be deferred. Any deferral will be based on commission priority to meet statewide air quality needs. The commission believes that anticipated state or federal regulations will, in all likelihood, require reductions in any emissions deferred.

TCE and SEED suggested additional criteria for determining when deferrals are appropriate: evaluation of the impact the emissions have on nonattainment or near-nonattainment areas, and a truth in hardship provision that requires proof of economic hardship with disclosure to the public so that the true economic cost of the control strategy to the state could be assessed. B&P commented that §116.816(d)(3) should be revised so that it provides for the consideration of impact of the reduction and the deferral on attaining or maintaining the NAAQS.

The commission has made no changes in response to these comments. The commission believes that the rules, as proposed and adopted, will allow the commission to consider the impact or benefit of deferrals on nonattainment and near-nonattainment areas. Information concerning the cost of controlling emissions will be an essential component of any application requesting a deferral.

EDF commented that the commission should explicitly state in §116.816(b) that the substantial emission reductions to be made in other specific air contaminants as a condition of a deferral need to be in addition to the requirements that would normally apply as part of a VERP.

The commission agrees that emission reductions needed for a deferral would be in addition to the amount of reductions of other specific air contaminants otherwise required by the VERP program. For example, if NO_x is reduced in lieu of SO_2, then the NO_x reductions used for a deferral would be in addition to the NO_x reductions otherwise required by VERP controls. Language in §116.816(d)(2) has been revised to clarify this requirement.

EDF commented that the rules should require submission of: 1) data on the economic health of the company; 2) length of time the company will commit to keep the plant operational, if a deferral is granted; and 3) which populations would benefit and which would be adversely impacted by a deferral.

The commission has made no changes in response to this comment. The commission believes that information concerning the cost of controlling emissions will be the most essential component of any application requesting a deferral. Since the commission believes that anticipated state or federal regulations will, in all likelihood, require reductions in any emissions deferred, commitments concerning length of time that a plant will remain operational are unnecessary. Any deferral will be based on commission priority to meet statewide air quality needs. In addition, the commission may not issue a VERP unless public health is being protected, therefore, the review of any deferral will include an analysis of benefit and impacts on off-property receptors.

EPE commented that the commission should define exceptional economic hardship, and the commenter also recommended that it be defined on the basis of cost of control or cost per ton of pollutant removed. EPE stated that the commission should also provide guidance on what constitutes specific technical impracticability.

The commission declines to define economic hardship because it is a term that is circumstantial in nature. Since this is a term used to determine eligibility for use of deferrals in lieu of VERP controls, the commission believes that each case should be determined on its own merit. The commission agrees that information concerning the cost of controlling emissions on a per ton basis will be an essential component of any application requesting a deferral. The commission believes that technical impracticability must be considered along with economic hardship, and is also circumstantial in nature. The commission will provide guidance, as necessary.

The EPA commented that §116.816(d)(3) requires the commission to consider the impact of emission reduction on attaining the NAAQS, and EPA understands the paragraph to mean that if the TNRCC plans to rely upon the VERP in its strategy to attain and maintain compliance with a NAAQS, it will consider such planning requirements in its decision to defer. The commenter understands that the commission will not defer implementation of a VERP that will interfere with attainment and maintenance of the NAAQS, or is otherwise inconsistent with the requirements of plan and control strategy.

Section 116.816(d)(3) allows the commission to consider the benefit that reductions of "other" specific air contaminants will have on attainment or maintenance of a NAAQS when deferring the requirement to reduce "certain" air contaminants. In other words, if a facility cannot reduce SO_2 due to economic hardship or technical impracticability, the commission might consider the benefit that a substantial reduction in NO_x would have on attainment or maintenance of the NAAQS for ozone. If the commission could determine that the reduction in NO_x would benefit the commission's priority to attain and maintain the ozone NAAQS, when weighed with its priority to protect public health and property, the deferral in SO_2 reductions could be granted, if the other criteria for granting a deferral are met. The commission may not issue any VERP which violates any commission regulation, including those intended for attainment and maintenance of the NAAQS. However, the commission is not committing to rely on VERP reductions in its strategy to attain and maintain compliance with the NAAQS in this adoption, but may do so in future SIP submittals. Therefore, the commission does not entirely agree with the EPA's understanding.

BMOH commented that there is no language in the statute that supports the commission's contention that deferrals be limited to exceptional economic hardship or technical impracticability problems. The commenter stated that while it is reasonable to review statements of legislative intent to illuminate the meaning of statutory terms, it is not appropriate to impose additional requirements based on statements of legislative intent. The granting of a deferral should be based upon the two criteria listed in the statute.

The commission believes that it is appropriate to limit deferrals to instances of economic hardship or technical impracticability problems. TCAA, §382.0519(e) provides the requirements for obtaining a deferral and allows the commission discretion in whether or not to grant a deferral, based on air quality priorities. In order to appropriately exercise this discretion, the commission believes that it is proper to look to legislative intent for guidance, and where appropriate, put that guidance in the rules. This specific issue was debated in the Legislature during the discussions concerning SB 766. Based on those discussions, the commission believes that deferrals are intended for use only when a facility has clearly documented to the commission that exceptional economic hardship or specific technical impracticability problems are a barrier to implementing the reductions that would be required by the permit. Further, it was expected that the discretionary authority to defer required emission reductions would be used by the commission only in very exceptional cases. Therefore, the commission has not revised the rules.

TIP commented that the commission should add language to §116.820 to make it clear that the commission intends to interpret modification consistent with existing interpretations.

The term "modification" is defined in both TCAA, §382.003, and in Chapter 116. The commission does not intend to interpret that term any differently for the purposes of the VERP program. Therefore, the rule has not been revised.

The EPA commented that it understands that once a facility obtains a VERP, any subsequent modification of that facility must go through NSR under Chapter 116, Subchapter B.

The commission agrees with that understanding.

EPE is concerned that the rules, as proposed, impose NSR requirements for major modifications to all modifications at a VERP facility, including modifications that would be considered minor at permitted facilities, and suggested revised language.

A VERP cannot be used for a modification. TCAA, §382.0519(d) requires any subsequent modification of a facility permitted under a VERP to use the regular NSR process. The purpose of §116.820 is to implement that requirement, and does not add any additional requirements, such as imposing NSR requirements for major modifications on all modifications at VERP facilities; therefore, the rules have not been revised.

GHASP commented that the commission should require adequate public notice of proposed permits in the news media, guaranteeing coverage of the entire affected area. TCEA and LWV commented that the commission should provide adequate and timely notice to the public. TCEA and NFN added that the commission should not depend on publication only in local newspapers. One individual commented that notice should be published in the largest circulation newspaper in the area and throughout the airshed. PC commented that the commission should give information about permit applications and proposed hearings to newspapers in communities affected by transport and make this information available on the commission's website. Three individuals commented that the commission should publish notice of VERP hearings in all news media in affected areas. Six individuals commented that notice of VERP hearings should be published statewide or in all affected areas statewide, not just in local newspapers. One individual commented that notice of a VERP hearing should be published within 100 miles of the facility. Finally, one individual commented that hearing notices should be published across the entire country. Two individuals commented that the commission should require public hearings.

TCAA, §382.05191 requires an applicant to publish notice of intent to obtain a VERP in accordance with TCAA, §382.056, which outlines the procedures required of applicants for air permits. TCAA, §382.05191 also provides alternate means of notice for small business VERP applicants. Permits must be noticed in a newspaper of general circulation in the municipality in which the facility is located or the nearest municipality. If applicable, bilingual newspaper notice is required. In all cases, applicants must post signs at the facility, and the permit application must be posted in a public place. In addition, HB 801, 76th Legislature, revised the public notice requirements for commission permits and provided additional opportunities for input, e.g., earlier notice to encourage public participation. In addition to the previous notice requirements, notices of intent to obtain a permit must include information about the opportunity to be included on mailing lists to receive updates on specific applications and the opportunity for public meetings. In addition, information regarding pending permit applications is posted on the commission's World Wide Web home page.

TCAA, §382.05191 also requires that the commission provide an opportunity for a public hearing, the submission of public comment, and notice of a decision on a VERP in the same manner as provided by TCAA, §382.0561 and §382.0562, which are the hearing and notice requirements for federal operating permits. Notice of VERP hearings are published in the same manner as notice of intent to obtain a permit, as previously noted. Because the commission believes that the notice requirements will provide ample information to ensure effective public participation, the rules have not been revised.

One individual commented that the commission should require both contested case hearings and notice and comment hearings so that the public can maximally protect itself from air pollution discrimination. Two individuals commented that the commission should require public hearings. One individual, TCE, and SEED commented that they are opposed to restricting hearings that have been deemed unreasonable. One individual added that "unreasonable" is an arbitrary term subject to abuse by the commission. The EPA commented that the commission should define what is a "reasonable" or "unreasonable" request, or cross-reference appropriate definitions, as necessary. LWV commented that the commission should provide opportunities for the public to contest the issuance of a VERP if the plant poses harmful health or environmental effects that need to be addressed.

The commission has made no changes in response to these comments. The public notice provisions in the rules implement TCAA, §382.05191, which requires that the commission provide an opportunity for a public hearing, the submission of public comment, and notice of a decision on a VERP in the same manner as provided by TCAA, §382.0561. That section provides the hearing and notice requirements for federal operating permits, and provides that the commission is not required to hold a hearing if the basis of a request by a person who may be affected is determined to be unreasonable. Therefore, reasonableness is the standard by which the commission must evaluate the basis of a hearing request. The commission believes that "reasonable" is a term that is circumstantial, but with a common understanding, and therefore does not need to be defined. Under §116.842, the commission must respond in writing to any person who commented during the public comment period, or at a hearing. That response must include a statement that any person affected by the decision of the commission may petition for rehearing and may seek judicial review. The effects of the facility on the health of the public can be a subject of the comments or hearing, as the commission cannot issue a VERP that is not protective of public health.

The EPA commented that §116.840(b) allows any person affected by the emissions from a grandfathered facility to request a hearing, and that the commission should address the need to provide opportunity for persons affected by a PERC to make such a request. EPA also referenced earlier comments on HB 801.

Any grandfathered facility obtaining a VERP must provide notice and opportunity for hearing to the public, regardless of whether controls or PERCs are used. Therefore, persons affected by a PERC, i.e., those affected by the grandfathered facility will have that opportunity. The commission may not have the authority to require public notice and opportunity for a hearing at the sites where the PERCs are actually generated. For example, if a wind power electric generating facility is constructed, and it emits no air contaminants, the commission does not have the authority to require a permit for that facility. By their nature, facilities at which PERCs are generated should not have increased emissions. Therefore, the commission would have no authority for requiring a permit, and therefore, public notice and opportunity for a hearing. If, for some reason, generating a PERC caused a significant increase in emissions at a facility, those increased emissions would have to be authorized by a permit with public notice and opportunity for hearing under the existing NSR rules. Therefore, the commission has addressed the need for a person affected by a PERC to have the opportunity to request a hearing. The commission will require public notice and opportunity for public hearing in accordance with the rule implementing HB 801, to the extent that they were not modified by SB 766. Therefore, the commission refers the EPA to the response to its comments provided in the adoption preamble for the rules implementing HB 801 in the September 24 and October 15, 1999 issues of the *Texas Register* (24 TexReg 8147 and 9015).

The EPA commented that §116.840(c) and §116.841(a) only apply to initial issuance of VERPs. The commenter stated that the commission should address why it is not requiring notice and comment hearings for subsequent revisions which significantly change a previously permitted VERP. Although §116.820 will address this concern with respect to modifications permitted under Chapter 116, Subchapter B, it may not cover changes which are not covered under Subchapter B.

All modifications of VERP permits must comply with Chapter 116, Subchapter B, which may subsequently allow modification under other chapters or subchapters, as appropriate. Any modifications would have to be done under the normal NSR permitting system, not the VERP system. The normal NSR system utilizes contested case hearings, when triggered, not notice and comment hearings. Therefore, there is no need to address why the commission is not requiring notice and comment hearings for VERP modifications.

The CAP commented that the commission should provide examples of the types of alternative notice that will be considered acceptable under 30 TAC §39.606. These examples should be included in the application package for a small business so that business owners can begin planning an approach to notice that will satisfy the commission.

The commission agrees, and will work with the CAP and interested parties to provide examples.

One individual commented that the commission should not limit incorporation of materials by reference in §116.841(g), because not doing so wastes paper and places the burden on citizens.

The commission disagrees that the criteria provided in the rule for incorporation by reference is limiting. The criteria ensures that documents supporting comments on permits are easily obtained and verifiable, since these documents will be included in the public record concerning a VERP application.

Seven individuals, GHASP, TCEA, NFN, LWV, and SC commented that the commission should establish fees at a level that will cover the real costs of administering the program. LWV added that this would ensure opportunities for public education and effective public participation in all aspects of the decision-making process. TCE and SEED suggested using a sliding scale fee that would be linked to emission reductions; the larger the reduction, the greater the savings. They believe that the $450 flat fee sends the wrong signal, since the stimulus for using a market-based mechanism has proven to be efficient and this is a golden opportunity. PC commented that fees should vary by the size of the emissions and/or by the length of time it will take to process applications, and that the commission should bill at $250 per hour for application processing. The commenter stated that the fees for GACT and PERCs are inadequate because these applications will require a great deal of analysis and staff work. EDF commented that the fees are too low, considering the amount of review required to consider fairly the permit applications. The commenter stated that the agency will be forced to rob other parts of the agency to pay for special permits for grandfathered plants.

The application fee for new or modified facilities is 0.15% of the capital cost of a project with a $450 minimum fee and a $75,000 maximum fee. This fee structure has proven adequate to cover the cost of implementing the NSR permitting program, historically. On the average, the commission expects VERP applications to be less complicated than applications for new or modified facilities, especially when ten-year old BACT is proposed and emission reductions result in an abbreviated health effects review. Therefore, the commission believes that the $450 flat fee is sufficient. Because $450 is a relatively affordable fee for most businesses, providing a sliding scale fee which would provide any amount of incentive would require raising the upper end to a level which would not encourage companies to apply for a VERP.

The CAP commented that the commission should require a flat fee of $100 for VERPs for small businesses. The commenter stated that since this is a voluntary program, fees at $450, and especially at $1,000 will serve as a strong disincentive for participation by small businesses.

The commission agrees, and will require a $100 flat fee for small businesses that use either ten-year old BACT or GACT, and has changed the rules accordingly. Because of the complexity of verifying and tracking PERCs and determining whether a deferral would result in a reduction which helps the commission meet its air quality priorities, the commission has not revised the rules with regard to the $1,000 fees.

TIP and BMOH supported a flat application fee of $450 for all VERP applications. GPM commented that the proposed PERC fee is too expensive, and that although the commission should cover the costs of the program, fees should not be punitive, since the permitting of grandfathered facilities is voluntary. BMOH commented that the commission has failed to provide a basis for why extensive commission staff time will be required to verify the conditions of deferrals and to validate PERCs. The commenter stated that the proposal continues to attempt to penalize deferral and PERC applications, because extensive staff may also be required to verify ten-year old BACT. BMOH further commented that the preamble provides no analysis of resource requirements necessary to process permit applications and does not present a comparative analysis of the differences between the three various permit options. If the commission has such information, BMOH requested that it be provided, and the comment period extended, so that interested persons may comment upon it.

The commission has not made changes in response to these comments. In order to grant a PERC, the commission must first determine that a good faith effort has been made to meet the VERP controls (through control cost analysis, availability of technology, etc.). Additionally, the commission must analyze projects, some of which it has no previous experience reviewing, to determine that resulting reductions compensate for a facility's excessive emissions in an amount and type sufficient to prevent air pollution to the degree comparable to the reductions which would have been necessary using VERP controls. The commission would also have to verify that these reductions are enforceable, permanent, quantifiable, real, and surplus.

Similarly, in order to grant a deferral, the commission must verify that substantial reductions in air contaminants will help the commission meet its air quality priorities and verify that the applicant has demonstrated exceptional economic hardship or that technical impracticability problems are a barrier to implementing the reduction which would have been required using VERP controls. In addition, before issuing a VERP under any option, the commission must verify that the public health and property will be protected. Implementing these two approaches is expected to be more resource intensive than verifying ten-year old BACT or GACT, since there is currently a list of ten-year old BACT, and since the starting point for GACT is well known by commission staff. Given the level of review, and the complexity of the issues involved, the commission believes that it is appropriate to assess the fee, as proposed.

EDF commented that an upgrade in control method should be required at renewal if a new technology has entered the market place or if the cost of a technology formerly deemed to be uneconomic has decreased during the life of the permit.

TCAA, §382.05192 requires VERPs to be renewed consistent with the provisions of TCAA §382.055. Under that section of the TCAA, the commission may impose more stringent requirements only to avoid a condition of air pollution or to ensure compliance with otherwise applicable air quality regulations. Therefore, the rules have not been revised.

One individual commented that the commission should develop no standard permits for VERP facilities, that a health effects review should be done and made public in a timely manner for each facility, and that standard permits are less rigorous, provide less oversight, and provide no meaningful public input. Four individuals commented that the commission should not allow standard permits in nonattainment counties. SC commented that the commission should limit the use of standard permits, and one individual, GHASP, TCEA, NFN, and LWV commented that the commission should limit the use of standard permits to minor sources.

The commission believes that it may be appropriate to create standard permits for VERPs when all of the conditions of the VERP program can be met, including protection of public health and property. Standard permits are a proven mechanism for permitting similar facilities that must meet similar requirements and will provide a streamlined process for encouraging VERP applications. The commission is currently in the process of developing a VERP standard permit for cotton gins and is considering standard permits for other types of similar facilities.

The requirements in standard permits are as rigorous as case-by-case permits. TCAA, §382.05195(a)(3) requires BACT to be implemented in standard permits, except for grandfathered facilities which apply for a standard permit prior to September 1, 2001. TCAA, §382.0519 requires ten-year old BACT or GACT at grandfathered facilities, and the commission will develop any standard permits for grandfathered facilities consistent with those standards. In addition, standard permits are enforced just as any other permit issued by the commission. Therefore, the commission does not believe that standard permits are less rigorous or result in less oversight. The commission conducts a protectiveness review while developing standard permits which should be valid for facilities which meet the requirements of the standard permit. In addition, the requirements of standard permits will be made public through mechanisms in §116.603 as part of the development process. Therefore, the commission does not believe that it is appropriate to do a health effects review for each facility that uses a standard permit.

Because the limitations and requirements of standard permits would be identical to those in numerous case-by-case permits, the commission does not believe that it is appropriate to limit the use of standard permits in nonattainment counties. The commission agrees that standard permits cannot be used to authorize major new sources or major modifications under the FCAA. However, to the extent that major sources do not trigger federal permitting requirements, the use of a standard permit could be allowed, if otherwise appropriate, i.e., the facility can meet standard permit control requirements.

ATINGP commented that the commission should consider developing a VERP standard permit for compressor stations and amine plants with ten-year old BACT for attainment areas and expand the language of proposed §116.602(b)(1) to clarify that a standard permit could be developed as a VERP. ATINGP supports the voluntary program in SB 766, as it provides much needed flexibility to the members in making a determination in the VERP program. Many of the grandfathered facilities owned and operated by the members are similar in nature and design; therefore, ATINGP believes that they would be candidates for a standard permit.

TCAA, §382.05193(a)(3) allows the commission the flexibility to develop VERP standard permits. The commission believes that it may be appropriate to create standard permits for VERPs when all of the conditions of the VERP program can be met, including protection of public health and property. Standard permits are a proven mechanism for permitting similar facilities that must meet similar requirements and will provide a streamlined process for encouraging VERP applications. Therefore, the commission is considering developing a VERP standard permit for compressor stations and amine plants, and will work with interested parties, including ATINGP, in making the determination. However, the commission believes that §116.602(b)(1) is broad enough to allow standard permits to be developed based on the controls specified under the VERP program. Therefore, the rule has not been revised.

The EPA commented that it understands that standard permits are issued to minor sources or for minor modifications at major sources and that standard permits could be issued to facilities required to have a federal operating permit. The commenter asked if these standard permits could be incorporated into a facility's federal operating permit through Chapter 122's permit modification provisions.

Chapter 116, Subchapter F does not allow standard permits to be used to authorize facilities which would be major new sources, major modifications, or reconstructions of major sources under the FCAA. Therefore, facilities at major sources authorized by standard permits would be included for reference only in federal operating permits, just as for any other state NSR authorization.

GPM commented that the commission should clarify that major grandfathered sources can use standard permits if ten-year old BACT is being met without further reductions. The commenter stated that the proposed rules appear to require emission reductions even if ten-year old BACT is being met.

The commission believes that it may be appropriate to create standard permits for VERPs when all of the conditions of the VERP program can be met, including ten-year old BACT, where appropriate. Further reductions, i.e. stricter controls, would not be required unless needed to ensure that the standard permit is protective of public health and property. Chapter 116, Subchapter F does not allow standard permits to be used to authorize major new sources or major modifications under the FCAA. However, to the extent that a modification at a major source does not trigger federal permitting requirements, the use of a standard permit could be allowed, if otherwise appropriate, i.e., the facility can meet standard permit control requirements. The rules have not been revised in response to this comment.

The CAP commented that the commission should better explain how existing authorizations will be impacted by new standard permit requirements. The commenter supports the expanded use of standard permits, but the commission should explain what changes will be necessary at small businesses currently operating under exemptions from permitting and what is the schedule for those changes.

This adoption does not directly affect the authorizations most often used by small businesses, i.e., exemptions from permitting and permits by rule. The new procedures adopted at this time for developing standard permits outside of rules will make it easier for the commission to develop and amend standard permits without sacrificing input from the public or interested parties. The commission does expect that some of the more widely used and complex exemptions from permitting and permits by rule will be redeveloped as standard permits. For example, the exemptions from permitting and permits by rule for concrete batch plants will likely be redeveloped as standard permits as soon as these new procedures are in place. However, the commission does not anticipate making decisions on redevelopment of other exemptions from permitting or permits by rule until the spring or summer of 2000. At that point, interested parties, including the CAP, will be consulted.

BMOH commented that the commission should clarify the proposed preamble discussion to explicitly provide that standard permits for grandfathered applicants will not require the installation of additional controls, except in the case that a grandfathered facility must obtain a standard permit to install reasonable available control technology under other requirements.

The commission agrees that the preamble could be clarified regarding the two types of standard permits which are not required to implement BACT, i.e., VERP standard permits and pollution control standard permits. The adoption preamble has been reworded to more clearly draw a distinction between these two types of standard permits. Standard permits for VERP applicants will require either ten-year old BACT or GACT.

The EPA commented that the term "APA" in §116.601(b) is not defined.

The tern "APA" is the Texas Administrative Procedure Act, which contains the procedures for rulemaking that the commission must follow. The term is defined in 30 TAC §3.2(2), concerning Definitions.

Mobil commented that the commission should amend the rules to allow, but not require, existing adopted standard permits to continue in force for facilities already authorized by them. The commenter stated that future issued standard permits would be utilized to permit the activities of applicants subsequent to the effective date of the amended rules. Facilities currently authorized under existing adopted standard permits should be allowed to maintain their existing authorization without the threat of having the terms and conditions under which they were constructed to be amended after the fact. Mobil further stated that this has been a basic precept of regulatory action in Texas and it could be considered an inappropriate taking by the state. B&P commented that the commission should limit the applicability of §116.605(d)(1) to issued standard permits.

The rule as proposed and adopted would allow existing standard permits to continue in force for facilities already authorized by them, unless the standard permit is repealed under the APA, and amended and reissued under the procedures outlined in §116.603. However, the commission does not agree that authorization by a standard permit allows a facility to be grandfathered from future changes to those terms and conditions. TCAA, §382.05195(f) requires that a facility authorized to emit air contaminants under a standard permit shall comply with an amendment to the standard permit. Section §382.05195(f) does not differentiate between adopted and issued standard permits.

The new provisions in §382.05195 and the rules implementing them do not meet the statutory elements for being a taking under Chapter 2007, Government Code. A "taking" as defined in §2007.002 as "a governmental action that affects private real property, in whole or in part or temporarily or permanently, in a manner that requires the governmental entity to compensate the private real property owner as provided by the Fifth and Fourteenth Amendments to the United States Constitution or Section 17 or 19, Article I of the Texas Constitution," or a governmental action that "affects and owner's private real property that is the subject of the governmental action, in whole or in part or temporarily or permanently, in a manner that restricts or limits the owner's right to the property that would otherwise exist in the absence of the governmental action and is the producing cause of a reduction of at least 25 percent in the market value of the affected private real property...." "Private real property" is defined as "an interest in real property recognized by common law, including a groundwater or surface water right of any kind, that is not owned by the federal government, this state, or a political subdivision of this state."

The proposal stated that the commission does not believe this action is a taking because it does not restrict private property in a manner that restricts or limits the owners right to the property that would exist in the absence of the proposed rules. 30 TAC §101.17 provides, in part, that a variance or a permit is granted in person, and does not attach to the realty to which it relates. Thus, a permit issued by the commission does not create a property right or restrict the use of real property. The new statutory requirement to comply with amended standard permits does not restrict an interest in private real property, (i.e. land). Rather, it requires owners to comply with revised rules in order to continue to operate facilities that emit air contaminants. Construction and operation under the terms of a standard permit is not mandatory. If a standard permit is revised (or revoked) such that the owner is no longer able to meet that standard permit, other NSR authorizations may be obtained. Nothing in the adopted rules compels owners to meet certain conditions in order to continue operating. Further, §2007.003(b) provides that the provisions of that statute do not apply to actions that are taken in response to a real and substantial threat to public health and safety, that significantly advances the health and safety purpose, and imposes no greater burden than is necessary to achieve the health and safety purpose. Since the revision or revocation of a standard permit will most likely result in conditions that are more restrictive, and thus more protective of public health and safety, these provisions meet the exception in §2007.003(b).

B&P commented that §116.601(b) should be revised to provide that standard permits adopted by the commission may remain in effect even after they are repealed to ensure consistency with the time frames proposed in §116.601(e), which allows a person to rely on repealed standard permits for some time after they are repealed.

The commission agrees with the comment and has changed the rule accordingly.

The EPA commented that §116.601(d) makes it appear conceivable that an existing standard permit that the commission repeals and replaces might survive for 19.9 years without undergoing renewal. The commenter stated that the commission should address whether this is the intended effect.

The commission agrees that if an adopted standard permit is repealed and replaced with an issued standard permit, and if the commission automatically converts the registrations as provided in §116.601(d), then renewal would occur on the tenth anniversary of the converted registration. Therefore, some facilities might have as long as 19.9 years between paperwork actions required by the registrant.

TxOGA commented that the commission should maintain a clear distinction between existing program requirements for adopted standard permits and new requirements for issued standard permits under the new program. SB 766 removed the requirement that standard permits be adopted by rule, but did not rescind the authority of the commission to permit construction or modification of facilities under existing standard permits previously adopted by rule. Therefore, TxOGA recommended that the proposed rule be amended to provide that: 1) adopted standard permits may be amended as provided under the APA; 2) registrations in effect under an adopted standard permit at the time the standard permit is amended shall continue in effect unless the permittee elects to re-register the facility construction or modification under, and subject to the terms of, the amended adopted standard permit; and 3) a person having a facility registered under an adopted standard permit that is repealed and replaced with an issued standard permit has the option (but not the requirement) to re-register the facility construction or modification under, and subject to the terms of, the issued standard permit as an alternative to continuing to operate under the terms of the repealed standard permit. The commenter stated that the recommended revisions would eliminate the provisions that existing authorizations to operate under adopted standard permits be subject to periodic renewal and that they could be revoked in the event that those standard permits were at some future date repealed. These provisions create additional work for industry and the agency and introduce an element of uncertainty as to future control requirements that make use of the standard permit much less desirable than in the past. TxOGA further stated that these provisions are not mandated by statute for amended standard permits, do not exist in any other part of the NSR program, and are inconsistent with the objectives of the standard permit program, chiefly streamlining. If additional controls are needed, the existing commission regulatory structure provides a more appropriate mechanism for adoption of such requirements. B&P commented that the commission should modify the rules to reflect the fact that a facility permitted under an adopted standard permit is not bound by amendments to the standard permit, whether achieved by an actual amendment or replacement with an issued standard permit. The commenter stated that while it is true that an issued standard permit must be met on an evolving basis, it is not true of existing adopted standard permits.

The commission agrees that SB 766 did not remove the authority of the commission to authorize construction or modification of facilities under existing, adopted standard permits, to the extent that those adopted standard permits are not amended. TCAA, §382.05195(f) requires that a facility authorized to emit air contaminants under a standard permit shall comply with an amendment to the standard permit. Section 382.05195(f) does not differentiate between adopted and issued standard permits. TCAA, §382.05195(e) requires the commission to establish rules for the amendment of a standard permit. Therefore, the commission believes that it is inappropriate to amend a standard permit under the APA, since the TCAA was just amended to require the development of this new process. The commission disagrees that additional work for industry and the agency will result from the new standard permit issuance procedures. The new procedures should make it easier for the commission to develop and amend standard permits, as needed, to provide a streamlined permitting process. Because standard permits are one-size-fits-all, and facilities authorized under standard permit are not subject to a full health effects review on a case-by-case basis, the commission feels that it is necessary to be able to revise standard permits as needed to ensure that the standard permit continues to reflect current technology and emission factors, and to ensure that facilities authorized by standard permit do not become a new class of grandfathered facilities. Therefore, the rules have not been revised.

The EPA commented that the commission should address whether §116.602(b)(2) is, by definition, only limited to minor source permitting, and that the commission should also address whether there are significance levels and where they are defined.

As proposed and adopted, §116.610 lists the general requirements that registrants for standard permits must meet. Section 116.610(b) and (d) prohibit authorization of new major sources, major modifications, or reconstruction of major sources, as defined in the referenced sections, from being authorized by a standard permit.

The EPA commented that the commission should ensure that the public notice provisions in §116.603 address the EPA comments submitted for the proposed rules implementing HB 801, that were provided in a letter dated August 16, 1999.

The EPA comments on the HB 801 rules referred to specific sections of 30 TAC Chapters 39 and 55, which provide the public participation requirements for case-by-case permitting. The public participation requirements in §116.603 are meant to provide a framework for issuance of standard permits similar to the APA framework for adoption of standard permits. Standard permits are not subject to Chapters 39 or 55. The commission refers the EPA to the analysis of testimony for the rules that implement HB 801 in the September 24 and October 15, 1999 issues of the *Texas Register* (24 TexReg 8147 and 9015).

The EPA commented that the commission should include in §116.604(4), the criteria which was discussed on page 7153 of the proposed preamble. The commenter stated that the rule should include a replicable procedure and the criteria that the commission will use to determine whether automatic registration is appropriate. The EPA stated that this will ensure that any decision to automatically renew a standard permit is consistent with state and federal requirements.

The commission believes that discussion of its intent regarding the concept for automatic renewal in the preamble is sufficient, since automatic renewal is a permissive, non-punitive option. The commission will not automatically renew a registration inconsistent with state or federal requirements, regardless of whether that specific criteria is listed in the rule.

BMOH commented that the commission should provide at least a 180-day renewal notice to registrants, as is the case for other permit renewals.

The commission agrees, and §116.604(3) has been revised accordingly.

While reviewing the provisions of §116.605(d)(3)(D), the staff noted that the rule referred to "best achievable control technology." This term has been corrected to refer to "best available control technology.

GPM and BP Amoco commented that the commission should add language to provide a grace period for facilities to comply with an amended standard permit, when the standard permit renewal period is imminent. The commenters stated that the commission should allow facilities that are within two years of renewal the option to renew at the subsequent renewal if changes cannot be quickly made to comply with the revised standard permit. TIP commented that the commission should provide much-needed flexibility in those facilities that are within two years of standard permit registration renewal when the commission adds new requirements or limitations to a standard permit, and that the facility should be required to come into compliance with the revised standard permits at the second renewal date after the standard permit amendment. The commenter stated that as written, the provision results in fundamental inequities based on different facilities having different standard permit renewal dates. While some facilities may have close to ten years to comply with the amended standard permit, others will be forced to come into compliance in as little as one or two years. EPE commented that the commission should allow a minimum of 24 months to comply with amendments to standard permits that require changes in control equipment or will involve significant capital expenditures.

The commission agrees that a grace period is appropriate, unless the amendment is necessary to protect public health, when it amends a standard permit and has revised the rules to include a minimum two-year grace period.

B&P commented that §116.605(e) should be revised to provide that registration is required at the same time the facility is required to comply with the amended standard permit under §116.605(d)(1).

The commission believes that the rule as proposed allows for registration and compliance dates to coincide and gives the commission the flexibility to set earlier registration dates in each standard permit. Delaying registration until the compliance date will not give commission staff adequate time to review the registration. Thus, a facility may not have the assurance that they meet the requirements of the revised standard permit prior to the compliance date. Therefore, the rule has not been revised.

The EPA asked, regarding §116.605, "If a standard permit is amended or revoked at a facility required to have a federal operating permit, would this amendment or revocation be reflected in the facility's Federal Operating Permit through Chapter 122's permit modification provisions"?

Chapter 116, Subchapter F does not allow standard permits to be used to authorize facilities which would be major new sources, major modifications, or reconstructions of major sources under the FCAA. Facilities at major sources authorized by standard permits would be included for reference only in federal operating permits, just as for any other state NSR authorization. Therefore, any amendment or revocation of a standard permit which is listed for reference only in a federal operating permit would be reflected using the administrative revision process.

EPE commented that the commission should revise §116.605(f) to specify a time period for applying for a permit or for an authorization under Chapter 106 if a standard permit is revoked. The commenter stated that the commission should also specify that a facility operating under a standard permit that has been revoked may continue to operate under the conditions of the revoked permit until the new permit is either approved or denied.

The commission believes that the revocation of a standard permit will be a rare event. If a standard permit is revoked, the notice to the registrant will specify a date for compliance with another appropriate authorization. The commission believes it would be inappropriate to allow the facility to continue to operate under a revoked standard permit if a revocation were based on health concerns. Therefore, no time period has been specified in the rule.

TxOGA commented that the commission should specifically provide that more stringent requirements or limitations in an amended issued standard permit, or revocations of an issued standard permit, shall be made applicable to a facility registered under the existing standard permit only when continued operation under the existing permit requirements contravenes the TCAA. The commenter stated that the commission was given broad discretion to amend or revoke an issued standard permit in such a manner that the new requirements or revocation would have to be applicable only to facilities constructed or modified under that standard permit after the effective date of the amendments, consistent with current NSR authority. This could be done by making new requirements date-specific, with permittees having the option to voluntarily re-register facilities under, and subject to the requirements of, the amended issued standard permit. In the case of revoked standard permits, the statutory intent could be accomplished by making the revocation prospective only. TxOGA believes that the proposed §116.605(d)-(f) may be broad enough to provide the agency with the discretion allowed by the statute, but they urged that the commission clarify its regulation to clearly state the extent of the agency's discretion in this regard.

TCAA, §382.05195(f) states that a facility authorized to emit air contaminants under a standard permit shall comply with an amendment to the standard permit. It does not limit the commission's discretion regarding the basis for an amendment. The proposed rules provided criteria the commission would consider when determining whether to amend or revoke a standard permit. The commission does not believe that the statute intends grandfathering in the context of standard permits, and that the statute provides a consistent regulatory basis for all facilities using standard permits. Therefore, the rule has not been revised to limit the applicability of amendments to standard permits to instances where the intent of the TCAA has been contravened. The commission disagrees that there is discretion under §382.05195(f) to provide the option for existing, unmodified facilities to continue operating under the previous version of the standard permit, indefinitely. However, as standard permits are amended or revoked, the commission will consider on a case-by-case basis whether existing facilities should continue to operate for a specified, extended period of time under the previous version of the standard permit.

BMOH commented that the commission should clarify that standard permits for existing facilities will only be amended to require additional controls if the commission finds that a condition of air pollution exists or there is a change in the method of operation of the unit operating under the standard permit. The commenter recommended either deleting §116.605(d)(3)(D); clarifying that existing registrants need not comply with amended standard permits to implement changes in BACT; creating additional standard permits for facilities constructed or modified after a certain date; or allowing them to convert a standard permit into a traditional NSR permit with the standard permit terms and conditions. The commenter stated that while SB 766 requires permittees to comply with amended permits, it does not limit the commission from establishing multiple standard permits for similar facilities based upon the date the facility was last modified. By way of comparison, under NSR, a facility is not subject to continual changes unless a modification is made. BMOH also commented that the commission should clarify its intentions on updating standard permits to reflect current BACT and to provide assurances in the rules that existing registrations will not be adversely affected by permit amendments to update BACT. GPM, BP Amoco, and TIP commented that the commission should set a very high bar for amending or revoking standard permits, and that standard permits should only be revisited if the permit is no longer protective of public health. The commenters disagreed with the provisions of §116.605(d)(3)(D) which would potentially revisit standard permits based on technology requirements, and stated that these provisions are inconsistent with other NSR provisions.

TCAA, §382.05195(f) states that a facility authorized to emit air contaminants under a standard permit shall comply with an amendment to the standard permit. Section 382.05195(f) does not limit the commission's discretion regarding the basis for an amendment. The commission believes that the statute intended for all similar facilities using standard permits to meet the same standard permit. Since the statute requires facilities to meet amended standard permits, the commission does not believe that it provides for the concept of grandfathering in the context of standard permits. In addition, the statute was amended to require BACT for all non-VERP standard permit applications. Accordingly, the commission believes that it is required to amend standard permits, at least for new or modified facilities, if BACT changes. Therefore, the rule has not been revised to limit the applicability of amendments to standard permits to instances where a condition of air pollution exists, there is a change in the method of operation, or BACT has changed. For the same reason, the commission believes that it would be inconsistent with the statute to maintain multiple standard permits applicable to similar facilities. The commission agrees that it might be appropriate to convert authorizations under a standard permit to an NSR permit if all the procedures for NSR initial issuance are followed, including public notice requirements. The rule has not been revised because applicants can apply for an NSR permit under the current rules. The commission believes that the appropriate flexibility for existing facilities would best be provided through the use of extended compliance dates in amended standard permits. The commission will consider, on a case-by-case basis, whether existing facilities should continue to operate for a specified, extended period of time under the previous version of the standard permit. Because of the ability to extend compliance dates in amended standard permits for existing facilities, and the opportunities that the issuance procedures provide for input by interested parties, the commission does not believe that existing registrations will be adversely affected by standard permit amendments.

BMOH commented that the commission should provide advanced written notice to existing registrants of proposed amendments to ensure full public participation in the process by those whose interests are directly affected.

The commission agrees that written notice will be provided to registrants and any persons requesting to be on a mailing list concerning amendment or revocation of a specific standard permit. Accordingly, §116.605(c) has been revised.

BMOH commented that there is no reason or basis under the TCAA for the commission to consider the amount of time that has elapsed since the last amendment to a specific standard permit when determining whether a standard permit should be amended. The commenter stated that the commission should focus on air pollution issues, and that for it to impose more rigorous controls merely due to the amount of time that has elapsed is not consistent with the TCAA.

By including the provision for consideration of time in §116.605(d)(3)(E), the commission was trying to provide some assurance that standard permits would not be frequently amended, unless requested by the affected parties or the public. However, since the commission has agreed to provide extended compliance dates for existing facilities, when appropriate, in each amended standard permit, the commission agrees that §116.605(d)(3)(E) is unnecessary, and it has been deleted.

BMOH commented that the commission provides no support for its conclusion that the proposed rules requiring compliance with amended standard permits will not have an adverse affect on the public. The commenter stated that the commission provides only conclusory statements in this regard; therefore, the analysis is flawed and does not comport with the APA.

Section 2001.0225 of the Government Code states that "before adopting a major environmental rule subject to this section, a state agency shall conduct a regulatory analysis that: considers the benefits and costs of the proposed rule in relationship to state agencies, local governments, the public, the regulated community, and the environment." If this comment was directed at adverse effects on the "public" as stated, those effects are largely unknown but are not anticipated to be significant.

If the comment was directed at adverse effects on the regulated community, it is anticipated that the proposed amendments related to revisions of standard permits could have adverse implications to certain facilities, but the standard permit process is optional and voluntary. It is not known how widespread adverse effects might be. However, the commission will work with interested and affected parties when amending standard permits to mitigate any adverse effects and has added language to §116.605 to clarify that compliance with an amended standard permit would not occur earlier than two years after the amendment, unless public health is being adversely affected.

In addition, §2001.0225 requires an analysis of the rule if the rule meets the definition of a "major environmental rule" and also meets the applicability requirements stated in the Act. If the rule is disqualified for either the definition or the applicability requirements, there is no requirement to accomplish the analysis. Because the commission believes that the provisions regarding standard permits do not constitute a major environmental rule and because the rule was also disqualified by failing to meet the applicability requirements, a full regulatory impact analysis is not required.

The CAP commented that the commission should establish methods for sharing registrations among multiple government agencies or units within the commission. A small business owner attempting to comply with numerous different regulations can unintentionally file these copies incorrectly, and may not be aware of any local programs having jurisdiction. The preference is one central contact at the commission who would make the information available to other agencies or relevant commission programs.

The CAP commented that the commission should establish methods for sharing registrations among multiple government agencies or units within the commission, and that a small business owner attempting to comply with numerous different regulations can unintentionally file these copies incorrectly, and may not be aware of any local programs having jurisdiction. The commenter's preference is one central contact at the commission who would make the information available to other agencies or relevant commission programs.

The commission agrees that appropriate methods should be developed to assist small businesses in their submittal of registrations to the commission and to local governments and commits to developing this assistance. The Air Permits Division and the Small Business and Environmental Assistance program, with input from the CAP, will work together to develop an acceptable solution.

GPM, BP Amoco, and TIP commented that §116.614 should be revised to indicate that no fee would be required for automatic standard permit renewal, since minimal agency time should be required on behalf of individual applicants.

The commission agrees, and has revised §116.614 accordingly.

The CAP commented that the commission should consider a flat fee of $100 for small businesses, and as a substitute, allow payment by installments as a secondary alternative. The commenter stated that the $450 fee in the proposal might present a financial challenge to small businesses when considered in addition to the expenses of complying with the standard permit.

The commission agrees that it may not always be appropriate to charge a fee for standard permits used by small businesses. For example, if an existing permit by rule is changed into a standard permit, the commission would need to consider the amount of agency review time that would be required when assessing whether or not a fee should be charged. If the commission determines that no fee or a lower fee should be charged for that particular standard permit, §116.614 allows the commission the discretion to make that determination on a case-by-case basis. Therefore, the rules have not been revised in response to the comment.

BMOH commented that the fee for a standard permit registration should fall in the range of $100-150, and that the preamble does not provide any analysis that the fee is necessary to recoup the commission's costs for administering the program as required by §382.062 of the TCAA.

The commission did not propose to change the existing fee of $450 for standard permit registrations. Instead, the proposal revised the rules to allow the commission the discretion to charge a fee, if any, other than $450 for a particular standard permit. If, in the future, the commission elects to charge a fee other than $450, the analysis will be provided on a case-by-case basis at that time and affected parties will have the opportunity to comment. Therefore, the rules have not been revised in response to the commenter.

Subchapter A. DEFINITIONS

30 TAC §116.16

STATUTORY AUTHORITY

The new section is adopted under Texas Health and Safety Code, TCAA, §382.011, which authorizes the commission to administer the requirements of the TCAA; §382.012, which provides the commission the authority to develop a comprehensive plan for the state's air; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; §382.051, which authorizes the commission to issue a permit for numerous similar sources; §382.0513, which authorizes the commission to establish and enforce permit conditions consistent with the TCAA; §382.0515, which requires applicants to provide information that assures compliance with state and federal laws and regulations; §382.0519, which authorizes the commission to issue VERPs; §382.05191, which requires the commission to establish public hearing procedures for VERPs; §382.05193, which authorizes the commission to issue a VERP based on emissions reductions; §382.05195, which authorizes the commission to issue a standard permit; §382.055, which authorizes the commission to establish procedures for review or renewal of a permit; §382.056, which authorizes the commission to require public notice of certain permit applications and procedures for requesting hearings and responding to comments; §382.0561, which authorizes hearing procedures for federal operating permits; §382.0562, which requires notices of decision; §382.061, which authorizes the commission to delegate permitting authority to the executive director; and Texas Water Code, §5.122, which authorizes the commission to delegate uncontested matters to the executive director.

§116.16. Voluntary Emission Reduction Permit Definitions.

The following words and terms, when used in Subchapter H of this chapter (relating to Voluntary Emission Reduction Permits), shall have the following meanings, unless the context clearly indicates otherwise. Airshed–

(1) For grandfathered facilities in nonattainment areas, the nonattainment area in which the facility is located.

(2) For grandfathered facilities in attainment areas, the region in which the facility is located, including any nonattainment area in that region: the East Texas Region or the West Texas Region, as defined in §101.330 of this title (relating to Electric Generating Facility Permits Definitions), or El Paso County.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9909011

Margaret Hoffman

Director, Environmental Law Division

Texas Natural Resource Conservation Commission

Effective date: January 11, 2000

Proposal publication date: September 10, 1999
For further information, please call: (512) 239-1966

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Subchapter F. STANDARD PERMITS

30 TAC §§116.601-116.606, 116.610, 116.611, 116.614

STATUTORY AUTHORITY

The new and amended sections are adopted under Texas Health and Safety Code, TCAA, §382.011, which authorizes the commission to administer the requirements of the TCAA; §382.012, which provides the commission the authority to develop a comprehensive plan for the state's air; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; §382.051, which authorized the commission to issue a permit for numerous similar sources; §382.0513, which authorizes the commission to establish and enforce permit conditions consistent with the TCAA; §382.0515, which requires applicants to provide information that assures compliance with state and federal laws and regulations; §382.0519, which authorizes the commission to issue VERPs; §382.05191, which requires the commission to establish public hearing procedures for VERPs; §382.05193, which authorizes the commission to issue a VERP based on emissions reductions; §382.05195, which authorizes the commission to issue a standard permit; §382.055, which authorizes the commission to establish procedures for review or renewal of a permit; §382.056, which authorizes the commission to require public notice of certain permit applications and procedures for requesting hearings and responding to comments; §382.0561, which authorizes hearing procedures for federal operating permits; §382.0562, which requires notices of decision; §382.061, which authorizes the commission to delegate permitting authority to the executive director; and Texas Water Code, §5.122, which authorizes the commission to delegate uncontested matters to the executive director.

§116.601. Types of Standard Permits.

(a) For the purposes of this chapter a standard permit is either:

(1) one that was adopted by the commission in accordance with Texas Government Code, Chapter 2001, Subchapter B, into §§116.617, 116.620, and 116.621 of this title (relating to Standard Permits for Pollution Control Projects; Installation and/or Modification of Oil and Gas Facilities; and Municipal Solid Waste Landfills); or

(2) one that is issued by the commission in accordance with §116.603 of this title (relating to Public Participation in Issuance of Standard Permits).

(b) Any standard permit in this subchapter adopted by the commission shall remain in effect until it is repealed under the APA. If any adopted standard permit is repealed and replaced, facilities may continue to be authorized until the date of registration required by subsection (e) of this section.

(c) A registration to use a standard permit adopted by the commission in this subchapter shall be renewed by the applicant under the requirements of §116.604 of this title (relating to Duration and Renewal of Registrations to use Standard Permits) by the tenth anniversary of the date of the original registration.

(d) If a standard permit in this subchapter adopted by the commission is repealed and replaced, with no changes, by a standard permit issued by the commission, any existing registration to use the repealed standard permit will be automatically converted to a registration to use the new standard permit, if the facility continues to meet the requirements. An automatically converted registration to use a standard permit shall be renewed by the applicant under the requirements of §116.604 of this title by the tenth anniversary of the date of the new registration.

(e) If a standard permit adopted by the commission in this subchapter is repealed and replaced with a standard permit issued by the commission, and the requirements of the standard permit are changed in the process, persons registered to use the repealed standard permit shall register to use the issued standard permit by the later of either the deadline established in the issued standard permit, or the tenth anniversary of the original registration. The commission shall notify, in writing, all persons registered to use the repealed standard permit of the date by which a new registration must be submitted. Persons not wishing to register for the issued standard permit shall have the option of applying for or qualifying for other applicable authorizations in this chapter or in Chapter 106 of this title (relating to Exemptions from Permitting).

§116.603. Public Participation in Issuance of Standard Permits.

(a) The commission will publish notice of a proposed standard permit in a daily or weekly newspaper of general circulation in the area affected by the activity that is the subject of the proposed standard permit. If the proposed standard permit will have statewide applicability, notice will be published in the daily newspaper of largest general circulation within each of the following metropolitan areas: Amarillo, Austin, Corpus Christi, Dallas, El Paso, Houston, the Lower Rio Grande Valley, Lubbock, the Permian Basin, San Antonio, and Tyler. In both cases, the commission will publish notice in the *Texas Register*.

(b) The contents of a public notice of a proposed standard permit shall be in accordance with §39.411 of this title (relating to Text of Public Notice) except where clearly not applicable. Each notice will include an invitation for written comments by the public regarding the proposed standard permit. The public notice will specify a comment period of at least 30 days and the public notice will be published not later than the 30th day before the commission issues a standard permit.

(c) The commission will hold a public meeting to provide an additional opportunity for public comment. The commission will give notice of a public meeting under this subsection as part of the notice described in subsection (b) of this section not later than the 30th day before the date of the meeting. The public comment period shall automatically be extended to the close of any public meeting.

(d) If the commission receives public comment related to the issuance of a standard permit, the commission will issue a written response to the comments at the same time the commission issues or denies the permit. The commission will make the response available to the public, and shall mail the response to each commenter.

(e) The commission will publish notice of its final action on the proposed standard permit and the text of its response to comments in the *Texas Register*.

(f) The commission will make a copy of any issued standard permit and response to comments available to the public for inspection at the commission's Office of Permitting, Remediation, and Registration in its Austin office, and also in the appropriate regional offices.

§116.604. Duration and Renewal of Registrations To Use Standard Permits.

An owner or operator who chooses to use a standard permit shall register to use a standard permit in accordance with §116.611 of this title (relating to Registration to Use a Standard Permit), unless otherwise specified in a specific standard permit.

(1) The registration to use a standard permit is valid for a term not to exceed ten years.

(2) The holder of a standard permit shall be required to renew the registration to use a standard permit by the date the registration expires. Any registration renewal shall include the requirements, as applicable, of §116.611 of this title (relating to Registration to Use a Standard Permit) and shall provide information determined by the commission to be necessary to demonstrate compliance with the requirements and conditions of the standard permit and with applicable state and federal regulations.

(3) The commission will provide written notice to registrants of the renewal deadline at least 180 days prior to the expiration of the registration.

(4) The commission may choose to renew registrations to use specific standard permits automatically, and, in such cases, will provide written notice to registrants.

§116.605. Standard Permit Amendment and Revocation.

(a) A standard permit remains in effect until amended or revoked by the commission.

(b) After notice and comment as provided by subsection (c) of this section and §116.603(b)-(f) of this title (relating to Public Participation in Issuance of Standard Permits), a standard permit may be amended or revoked by the commission.

(c) The commission will publish notice of its intent to amend or revoke a standard permit in a daily or weekly newspaper of general circulation in the area affected by the activity that is the subject of the standard permit. If the standard permit has statewide applicability, then the requirement for newspaper notice shall be accomplished by publishing notice in the daily newspaper of largest general circulation within each of the following major metropolitan areas: Austin, Dallas, and Houston. The commission will also provide written notice to registrants and any persons requesting to be on a mailing list concerning a specific standard permit. In both cases, the commission will publish notice in the *Texas Register*.

(d) The commission may, through amendment of a standard permit, add or delete requirements or limitations to the permit.

(1) To remain authorized under the standard permit, a facility shall comply with an amendment to the standard permit on the later of either the deadline the commission provides in the amendment or the date the facility's registration to use the standard permit is required to be renewed. The commission may not require compliance with an amended standard permit within 24 months of its amendment unless it is necessary to protect public health.

(2) Before the date the facility is required to comply with the amendment, the standard permit, as it read before the amendment, applies to the facility.

(3) The commission will consider the following when determining whether to amend or revoke a standard permit:

(A) whether a condition of air pollution exists;

(B) the applicability of other state or federal standards that apply or will apply to the types of facilities covered by the standard permit;

(C) requests from the regulated community or the public to amend or revoke a standard permit consistent with the requirements of the TCAA; and

(D) whether the standard permit requires best available control technology.

(e) The commission may require, upon issuance of an amended standard permit, or on a date otherwise provided, the owner or operator of a facility to submit a registration to use the amended standard permit in accordance with the requirements of §116.611 of this title (relating to Registration to Use a Standard Permit).

(f) If the commission revokes a standard permit, it will provide written notice to affected registrants prior to the revocation of the standard permit. The notice will advise registrants that they must apply for a permit under this chapter or qualify for an authorization under Chapter 106 of this title (relating to Exemptions from Permitting).

(g) The issuance, amendment, or revocation of a standard permit or the issuance, renewal, or revocation of a registration to use a standard permit is not subject to Texas Government Code, Chapter 2001.

§116.614. Standard Permit Fees.

Any person who registers to use a standard permit or an amended standard permit, or to renew a registration to use a standard permit shall remit, at the time of registration, a flat fee of $450 for each standard permit being registered, unless otherwise specified in a particular standard permit. No fee is required if a registration is automatically renewed by the commission. All standard permit fees will be remitted in the form of a check or money order made payable to the Texas Natural Resource Conservation Commission (TNRCC) and delivered with the permit registration to the TNRCC, P.O. Box 13088, MC 214, Austin, Texas 78711-3088. No fees will be refunded.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9909012
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Director, Environmental Law Division
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Effective date: January 11, 2000
Proposal publication date: September 10, 1999
For further information, please call: (512) 239-1966

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Subchapter H. VOLUNTARY EMISSION REDUCTION PERMITS

30 TAC §§116.810-116.814, 116.816, 116.820, 116.840-116.842, 116.850, 116.860, 116.870

STATUTORY AUTHORITY

The new sections are adopted under Texas Health and Safety Code, TCAA, §382.11, which authorizes the commission to administer the requirements of the TCAA; §382.012, which provides the commission the authority to develop a comprehensive plan for the state's air; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; §382.051, which authorized the commission to issue a permit for numerous similar sources; §382.0513, which authorizes the commission to establish and enforce permit conditions consistent with the TCAA; §382.0515, which requires applicants to provide information that assures compliance with state and federal laws and regulations; §382.0519, which authorizes the commission to issue VERPs; §382.05191, which requires the commission to establish public hearing procedures for VERPs; §382.05193, which authorizes the commission to issue a VERP based on emissions reductions; §382.05195, which authorizes the commission to issue a standard permit; §382.055, which authorizes the commission to establish procedures for review or renewal of a permit; §382.056, which authorizes the commission to require public notice of certain permit applications and procedures for requesting hearings and responding to comments; §382.0561, which authorizes hearing procedures for federal operating permits; §382.0562, which requires notices of decision; §382.061, which authorizes the commission to delegate permitting authority to the executive director; and Texas Water Code, §5.122, which authorizes the commission to delegate uncontested matters to the executive director.

§116.810. Eligibility.

(a) The owner or operator of a grandfathered facility may apply for a permit to operate that facility under this subchapter. Applications under this subchapter must be submitted before September 1, 2001.

(b) Applications for a voluntary emission reduction permit (VERP) shall be submitted under the seal of a Texas licensed professional engineer, if required by §116.110(e) of this title (relating to Applicability).

(c) The owner or authorized operator of the grandfathered facility, group of facilities, or account is responsible for applying for the VERP and for complying with this subchapter.

§116.811. Voluntary Emission Reduction Permit Application.

Any application for a voluntary emissions reduction permit (VERP) must include a completed Form PI-1V Voluntary Emission Reduction Permit Application. The Form PI-1V must be signed by an authorized representative of the applicant. The Form PI-1V specifies additional support information which must be provided before the application is deemed complete. In order to be granted a VERP, the owner or operator of the grandfathered facility shall submit information to the commission which demonstrates that all of the following are met.

(1) Protection of public health and welfare. The emissions from the grandfathered facility will comply with all rules and regulations of the commission and with the intent of the TCAA, including protection of the health and physical property of the people.

(2) Measurement of emissions. The VERP may have provisions for measuring the emission of air contaminants as determined by the commission. These may include the installation of sampling ports on exhaust stacks and construction of sampling platforms in accordance with guidelines in the "Texas Natural Resource Conservation Commission Sampling Procedures Manual," portable analyzers, or emissions calculations if a known process variable is monitored.

(3) Control method.

(A) Control method in attainment areas. A grandfathered facility in an attainment area shall use an air pollution control method that is at least as beneficial as the best available control technology (BACT) that the commission required or would have required for a facility of the same class or type as a condition of issuing a permit or permit amendment 120 months before the submittal of the VERP application considering the age and remaining useful life of the facility, except as provided by subparagraphs (B), (C), and (D) of this paragraph.

(B) Control method in nonattainment areas and the following attainment counties: Bexar, Gregg, Harrison, Nueces, Smith, Travis, and Victoria. A grandfathered facility located in a nonattainment area for a national ambient air quality standard, or a grandfathered facility which emits volatile organic compounds or nitrogen oxides in an attainment county listed in this subparagraph, shall use the more stringent of:

(i) a control method at least as beneficial as that described in subparagraph (A) of this paragraph; or

(ii) a control method that the commission finds is demonstrated to be generally achievable for facilities in that area of the same type that are permitted under this section, considering the age and remaining useful life of the facility.

(C) Emissions reductions may be deferred at grandfathered facilities according to §116.816 of this title (relating to Deferral of Emission Reductions).

(D) A VERP may be issued for a grandfathered facility:

(i) that makes a good faith effort to make equipment improvements and emission reductions necessary to meet the requirements of subparagraph (A) or (B) of this paragraph;

(ii) that, in spite of the effort, cannot reduce the facility's emissions to the degree necessary for the issuance of the permit; and

(iii) whose owner or operator acquires a sufficient number of emission reduction credits under the program established under §116.812 of this title (relating to Project Emission Reduction Credits) to offset the emissions exceeding those which would otherwise be allowed under subparagraph (A) or (B) of this paragraph.

(4) New Source Performance Standards (NSPS). The emissions from each affected facility as defined in 40 Code of Federal Regulations (CFR) Part 60 will meet at least the requirements of any applicable NSPS as listed under Title 40 CFR Part 60, promulgated by EPA under authority granted under FCAA, §111, as amended.

(5) National Emission Standards for Hazardous Air Pollutants (NESHAPS). The emissions from each facility as defined in 40 CFR Part 61 will meet at least the requirements of any applicable NESHAPS, as listed under 40 CFR Part 61, promulgated by EPA under authority granted under FCAA, §112, as amended.

(6) NESHAPS for source categories. The emissions from each affected facility shall meet at least the requirements of any applicable maximum available control technology (MACT) standard as listed under 40 CFR Part 63, promulgated by EPA under FCAA, §112, or as listed under Chapter 113, Subchapter C of this title (relating to National Emissions Standards for Hazardous Air Pollutants for Source Categories (FCAA, §112, 40 CFR 63)).

(7) Performance demonstration. The grandfathered facility will achieve the performance specified in the permit application. The commission may require the applicant to submit additional engineering data after a VERP has been issued in order to demonstrate further that the grandfathered facility will achieve the performance specified in the permit. In addition, the commission may require initial compliance testing to determine ongoing compliance through engineering calculations based on measured process variables, parametric or predictive monitoring, stack monitoring, or stack testing.

(8) Nonattainment review. A grandfathered facility in a nonattainment area shall comply with all applicable requirements under Subchapter B, Division 5 of this chapter (relating to Nonattainment Review).

(9) Prevention of Significant Deterioration (PSD) review. A grandfathered facility in an attainment area shall comply with all applicable requirements under Subchapter B, Division 6 of this chapter (relating to Prevention of Significant Deterioration Review).

(10) Air dispersion modeling or ambient monitoring. The commission may require computerized air dispersion modeling and/or ambient monitoring to determine the air quality impacts from the grandfathered facility.

(11) Federal standards of review for constructed or reconstructed major sources of hazardous air pollutants. If the grandfathered facility is an affected source (as defined in §116.15(1) of this title (relating to Section 112(g) Definitions)), the affected source shall comply with all applicable requirements under Subchapter C of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)).

(12) Application content. In addition to any other requirements of this subchapter, the applicant shall:

(A) identify each facility to be included in the VERP;

(B) identify the air contaminants emitted;

(C) provide emission rate calculations;

(D) propose a control method; and

(E) identify the date by which the control method will be implemented.

§116.812. Project Emission Reduction Credits.

(a) Project emission reduction credits (PERC) shall be granted to the owner or operator of a grandfathered facility for the purpose of complying with §116.811(3)(D) of this title (relating to Voluntary Emission Reduction Permit Application) if the owner or operator conducts an emission reduction project to compensate for the facility's emissions exceeding the emission rate which would otherwise be required under §116.811(3) of this title, provided:

(1) the emission reduction project reduces emissions in the airshed in which the grandfathered facility is located; and

(2) the emission reduction project reduces net emissions from one or more sources in this state in an amount and type sufficient to prevent air pollution to a degree comparable to the amount of the reduction in the facility's emissions that would be necessary to comply with §116.811(3) of this title.

(b) Qualifying emission reduction projects include, but are not limited to:

(1) generation of electric energy by a low-emission method, including:

(A) wind power;

(B) biomass gasification power; and

(C) solar power;

(2) the purchase and destruction of high-emission automobiles or other mobile sources;

(3) the reduction of emissions from a permitted facility that emits air contaminants to a level significantly below the levels necessary to comply with the facility's permit;

(4) a carpooling or alternative transportation program for the owner's or operator's employees;

(5) a telecommuting program for the owner's or operator's employees; and

(6) the replacement by a motor vehicle fleet owner or operator of the fleet's primary fuel to either a lower-sulfur fuel than required by state or federal law, or the use of an alternative fuel approved by the commission under TCAA, §382.131(1).

(c) Applications for voluntary emission reduction permits (VERP) must demonstrate that any proposed PERCs meet the following criteria, as applicable. The PERC must be:

(1) enforceable by the commission;

(2) permanent, meaning that the emission reduction is unchanging for the remaining life of the source;

(3) quantifiable, so that the emission reduction can be measured or estimated with confidence using replicable techniques;

(4) surplus, such that the emission reduction is not otherwise required of a facility by a state or federal law, regulation, or agreed order; and

(5) a real reduction in which actual emissions are reduced.

(d) A VERP for a grandfathered facility participating in the PERC program will include a permit condition requiring the successful completion of the project or projects for which the facility owner or operator acquires the credits.

(e) Emission reduction credits acquired under this section are not transferrable.

§116.816. Deferral of Emission Reductions.

(a) A voluntary emission reduction permit (VERP) may defer the requirement to reduce emissions of certain air contaminants.

(b) To qualify for a deferral of emission reductions, an applicant must specifically request a deferral of reductions of certain air contaminants and shall demonstrate how substantial emission reductions will be made in other specific air contaminants.

(c) The commission may grant a deferral based on its prioritization of air contaminants, as necessary, to meet local, regional, and statewide air quality needs and only if the applicant has clearly demonstrated that exceptional economic hardship or specific technical impracticability problems are a barrier to implementing the reduction required by the VERP.

(d) The commission will consider the following criteria for prioritizing air quality needs to determine whether to grant a deferral:

(1) the location of the grandfathered facility;

(2) the size of the reduction of emissions of other specific air contaminants and whether the reductions are in addition to the reductions that are required for other specific air contaminants by §116.811(3) of this title (relating to Voluntary Emission Reduction Permit Application);

(3) the impact of the reduction of emissions of other specific air contaminants and the deferral on attaining National Ambient Air Quality Standards (NAAQS);

(4) anticipated state or federal regulations that may require reductions of the air contaminants being deferred; and

(5) the benefit to public health from the reduction of other specific air contaminants versus the deferral.

§116.840. Public Participation for Initial Issuance.

(a) An applicant for a voluntary emission reduction permit (VERP) shall publish notice of intent to obtain the permit in accordance with Chapter 39, Subchapters H and K of this title (relating to Applicability and General Provisions; and Public Notice of Air Quality Applications).

(b) Any person who may be affected by emissions from a grandfathered facility may request the commission to hold a notice and comment hearing on the VERP application. The public comment period shall end 30 days after the publication of Notice of Receipt of Application and Intent to Obtain Permit under §39.418 of this title (relating to Notice of Receipt of Application and Intent to Obtain Permit). Any hearing request must be made in writing during the 30-day public comment period.

(c) Any hearing regarding initial issuance of a VERP shall be conducted under the procedures in §116.841 of this title (relating to Notice and Comment Hearings for Initial Issuance) and not under the APA.

(d) The commission's response to public comments and the notice of its decision on whether to issue or deny a VERP will be conducted under the procedures in §116.842 of this title (relating to Notice of Final Action).

(e) A person affected by a decision to issue or deny a VERP may seek review, as appropriate, under the appropriate procedure in Chapter 50 of this title (relating to Action on Applications and Other Authorizations), and may seek judicial review under TCAA, §382.032, relating to Appeal of Commission Action.

§116.842. Notice of Final Action.

(a) After the public comment period or the conclusion of any notice and comment hearing, the commission will send notice by first-class mail of the final action on the application to any person who commented during the public comment period or at the hearing, and to the applicant.

(b) The notice must include the following:

(1) the response to any comments submitted during the public comment period;

(2) identification of any change in the conditions of the draft permit and the reasons for the change; and

(3) a statement that any person affected by the decision of the commission may petition for a rehearing under the appropriate procedure in Chapter 50 of this title (relating to Action on Applications and Other Authorizations) and may seek judicial review under TCAA, §382.032, relating to Appeal of Commission Action.

§116.850. Voluntary Emission Reduction Permit Application Fee.

Any person who applies for a voluntary emission reduction permit (VERP) shall remit a fee.

(1) If the grandfathered facility will use a control method at least as stringent as those defined in §116.811(3)(A) or (B) of this title (relating to Voluntary Emission Reduction Permit Application), the application fee shall be $450.

(2) If the grandfathered facility will defer emission reductions under §116.811(3)(C) of this title, or if the grandfathered facility will use emission reduction credits under §116.811(3)(D) of this title, the application fee shall be $1,000.

(3) Only one of the applicable fees required in paragraphs (1) and (2) of this section shall be remitted with a single VERP application which proposes to control more than one facility at an account. If more than one facility is included in a single VERP application, the applicant shall remit the highest of the applicable fees.

(4) Notwithstanding paragraph (1) of this section, the maximum fee for a VERP for a small business, as defined in FCAA, §507(c), shall be $100, if the grandfathered facility will use a control method at least as stringent as those defined in §116.811(3)(A) or (B) of this title.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9909013

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Texas Natural Resource Conservation Commission

Effective date: January 11, 2000

Proposal publication date: September 10, 1999

For further information, please call: (512) 239-1966

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Chapter 116. CONTROL OF AIR POLLUTION BY PERMITS FOR NEW CONSTRUCTION OR MODIFICATION

The Texas Natural Resource Conservation Commission (TNRCC or commission) adopts new §116.18, Electric Generating Facility Permits Definitions; §116.910, Applicability; §116.911, Electric Generating Facility Permit Application; §116.912, Electric Generating Facility Permit Application for Electing Electric Generating Facilities; §116.913, General and Special Conditions; §116.914, Emissions Monitoring and Reporting Requirements; §116.916, Permits for Grandfathered and Electing Electric Generating Facilities in El Paso County; §116.920, Public Participation for Initial Issuance; §116.921, Notice and Comment Hearings for Initial Issuance; §116.922, Notice of Final Action; §116.930, Modifications; and §116.931, Renewal. Sections 116.18, 116.910 - 116.914, 116.916, 116.920 - 116.922, and 116.931 are adopted with changes to the proposed text as published in the September 10, 1999 issue of the *Texas Register* (24 TexReg 7163). Section 116.930 is adopted without changes and will not be republished. The new sections will be submitted as a proposed revision to the state implementation plan (SIP).

BACKGROUND AND SUMMARY OF THE FACTUAL BASIS FOR THE ADOPTED RULES

Senate Bill 7 (SB 7), 76th Legislature, 1999, amended Texas Utilities Code (TUC), Title 2, concerning Public Utility Regulatory Act, Subtitle B, concerning Electric Utilities, and created a new TUC, Chapter 39, concerning Restructuring of Electric Utility Industry. SB 7 requires the commission to implement the permitting and allowance requirements of new TUC, §39.264, concerning Emissions Reductions of "Grandfathered Facilities."

Section 39.264 requires electric generating facilities (EGF) that were existing on January 1, 1999, and that were not subject to the requirement to obtain a permit under Texas Clean Air Act (TCAA), §382.0518(g) to obtain a permit from the commission. These facilities are referred to as grandfathered facilities. A grandfathered facility is one that existed at the time the Legislature amended the TCAA in 1971. These facilities were not required to comply with (i.e., grandfathered from) the then new requirement to obtain permits for construction or modifications of facilities that emit air contaminants.

These new sections are adopted concurrently with amendments and new sections in 30 TAC Chapter 101, concerning General Rules. The new Division 2, concerning Emission Banking and Trading of Allowances, in the new Chapter 101, Subchapter H, concerning Emissions Banking and Trading, sets out the allowance system to be used to assist grandfathered and electing EGFs in meeting the emission reduction requirements of TUC, §39.264. The purpose of the rulemaking in these chapters is to implement permit and emission control requirements, including emission banking and trading of allowances (EBTA), for grandfathered and electing EGFs and related permit application and public notice procedures. The permit application and public notice procedures are the subject of these amendments to Chapter 116. The adopted amendments to Chapter 101 are published in this issue of the *Texas Register*.

TUC, §39.264 requires owners or operators of grandfathered EGFs to apply for a permit to emit nitrogen oxides (NO_x) and, for coal-fired grandfathered EGFs, sulfur dioxide (SO_2) and particulate matter (PM) through opacity limitations. These applications are due on or before September 1, 2000. A grandfathered EGF that does not obtain a permit may not operate after May 1, 2003, unless the commission finds good cause for an extension. It is the intent of TUC, §39.264 that for the 12-month period beginning May 1, 2003, and for each 12-month period following, annual emissions of NO_x from grandfathered EGFs not exceed 50% of the NO_x emissions reported to the commission for 1997. Furthermore, it is the intent of the legislation that emissions of SO_2 from coal-fired grandfathered EGFs not exceed 75% of the SO_2 emissions reported to the commission in 1997. The described emission limitations may be satisfied by using control technology or by participating in the banking and trading of allowances. In addition, TUC, §39.264(e) requires electric generating facility permit (EGFPs) for coal-fired, grandfathered EGFs to contain appropriate opacity limitations provided by the commission's rules in §111.111, of this title, Requirements for Specified Sources, thus permitting emissions of particulate matter.

Persons, municipal corporations, electric cooperatives, and river authorities owning permitted EGFs may elect to become subject to the permitting requirements and emission reductions. A municipal corporation, electric cooperative, or river authority may exclude any grandfathered EGF with a nameplate capacity of 25 megawatts or less from permitting and emission reduction requirements. TUC, §39.264(d) requires notice of the intent to exclude these grandfathered EGFs by January 1, 2000.

SECTION BY SECTION DISCUSSION

The new §116.18 contains the following definitions. The definitions of "Allowance," "Coal," "Coal-fired," "Compliance account," "Control period," "Electric generating facility," "Electing electric generating facility," "Grandfathered electric generating facility," and "Person" were all revised to cross-reference concurrently adopted definitions of these terms in 30 TAC §101.330, Definitions. "Nameplate capacity" means the maximum electrical output (expressed in megawatts) that an EGF can sustain over a specified period of time when not restricted by seasonal or other deratings. This definition is consistent with the definition used in the Federal Clean Air Act (FCAA) Amendments of 1990, Acid Rain Program. The commission believes that using this definition will reduce any confusion for grandfathered EGFs that are potentially subject to both the Acid Rain Program and the EBTA program proposed under Chapter 101, Subchapter H, Division 2. A "Peaking unit" is an EGF that has: 1) an average capacity factor of no more than 10% during the past three calendar years; and 2) a capacity factor of no more than 20% in each of those calendar years. "Capacity factor" is either: 1) the ratio of an EGF's actual annual electric output (expressed in megawatt-hours) to the EGF's nameplate capacity times 8,760 hours; or 2) the ratio of an EGF's annual heat input (in millions of British thermal units (MMBtu)) to the EGF's maximum design heat input (in MMBtu) times 8,760 hours. Both terms, "Peaking unit" and "Capacity factor," are consistent with the same terms in the FCAA Acid Rain Program.

Section 116.910 states that a permit under this Subchapter I would authorize emissions of NO_x for any grandfathered EGF, and PM through opacity limitations and emissions of SO_2 for coal-fired grandfathered EGFs. Owners or operators of electing EGFs may opt to obtain allowances under the EBTA in Chapter 101, Division 2. The electing EGF's existing new source review (NSR) permit will be altered using the procedures in §116.116(c). This NSR permit alteration will ensure that the existing NSR permit is changed to cross-reference to the EGFP. Section 116.910 specifies that the owner or operator who is authorized to act for the owner of a grandfathered or electing EGF is responsible for complying with Subchapter I. Consistent with TUC, §39.264(d), a municipal corporation, electric cooperative, or river authority may exclude any grandfathered EGF with a nameplate capacity of 25 megawatts or less from Subchapter I. The municipal corporation, electric cooperative, or river authority must notify the commission by January 1, 2000, of its intent to exclude those grandfathered EGFs. In response to comments, the commission has revised §116.910(d) to allow municipal corporations, electric cooperatives, or river authorities to notify the commission of its intent to obtain a permit after January 1, 2000. Applications must still be submitted by the statutory deadline of September 1, 2000. A new §116.910(g) was added to the adopted rule that excludes an EGF that generates electric energy primarily for internal use, but that during 1997 sold, to a utility power distribution system, less than one-third of its potential electrical output capacity or less than 219,000 megawatt-hours. This exclusion eliminates cogeneration facilities that the commission believes were not intended to be included in this program. The reference to 219,000 megawatt-hours is added to exempt small cogenerators who may exceed the one-third limitation. This is more consistent with the Acid Rain Program exemption for affected units.

TUC, §39.264 requires grandfathered EGFs to obtain a permit from the commission that authorizes the emission of NO_x and, for coal-fired EGFs, PM through opacity limitations and SO_2. Grandfathered EGFs also emit products of combustion such as carbon monoxide (CO) and volatile organic compounds (VOC). At a coal-fired grandfathered EGF, the emissions may include mercury as well. The commission believes that the TUC, §39.264 authorization was only intended to authorize NO_x and, if applicable, PM through opacity limitations and SO_2.

The commission also believes that the intent of TUC, §39.264 was to eliminate the grandfathered status of EGFs. However, it is unclear how TUC, §39.264 authorizes or requires the permitting of anything other than NO_x and for coal-fired EGFs, PM through opacity limitations and SO_2. Furthermore, if the commission were to permit these other air contaminants in an EGFP, it is unclear what standards should be applied to these air contaminants. Therefore, the commission will use the emission control standards of the voluntary emission reduction permit (VERP) program adopted concurrently in this issue of the *Texas Register* under 30 TAC Chapter 116, Subchapter H, Voluntary Emission Reduction Permits. These other air contaminants from the EGFs will be reviewed under the requirements of the VERP program, but would only go through the public notice process one time.

The commission believes that it is appropriate to rely on the control methods and health effects requirements of the VERP program for the other air contaminants. The VERP program provides control method options that depend on the location of a grandfathered facility. The VERP program also describes the suggested methods for a health effects review for grandfathered facilities. The reliance on the VERP control methods and health effects review will provide a consistent basis of review for the other emissions from all grandfathered EGFs. The commission does not think it is appropriate to merely include other emissions in a grandfathered EGF's permit without a review of control methods and, if necessary, impacts. This is consistent with the commission's longstanding policy to not treat certain facilities as being "permitted" simply because the facilities are consolidated into an existing permit. For example, a facility that was originally authorized by an exemption will continue to be authorized under the exemption even though the exemption is consolidated with an NSR permit during an amendment or at renewal. The final rules do not require applicants to permit these other air contaminants from EGFs.

Many power plants may have other grandfathered support facilities such as fuel storage tanks or coal handling facilities that are not EGFs. Because TUC, §39.264 addresses only those facilities which generate electricity for compensation, these support facilities are not explicitly required to obtain a permit under TUC, §39.264. To encourage the permitting of grandfathered support facilities, these facilities could apply for a VERP which would be consolidated with the EGFP. This would enable all the grandfathered facilities and EGFs at a site to go through a consolidated permitting process. Thus, all grandfathered facilities and EGFs would only go through the public notice process one time.

To address electing EGFs, §116.910(b) provides that the existing NSR permit be altered using the procedures in §116.116(c), Alterations. The altered NSR permit would continue to authorize emissions of all air contaminants, and would include a reference to the EGFP. The EGFP will contain the general and special conditions for electing EGFs. The unchanged, existing NSR permit conditions would not be subject to public notice since that permit will only be altered to reflect the existence of the EGFP.

The new §116.911 contains application procedures for grandfathered and electing EGFs to obtain an EGFP. As specified by TUC, §39.264(e), the new §116.911 requires owners or operators of grandfathered and electing EGFs to apply for a permit on or before September 1, 2000. The section also contains information concerning general content of the permit application for both grandfathered and electing EGFs. Emissions of air contaminants other than NO_x or, if applicable, PM through opacity limitations and SO_2 from an electing EGF already authorized by Chapter 116, are not required to be authorized under this subchapter. An EGFP will include provisions for measurement of emissions, monitoring, and reporting to calculate actual emissions over a control period. Although control technology is not explicitly required under TUC, §39.264, grandfathered or electing EGFs may propose the use of controls in their initial applications. The new provisions in §116.911(a)(2) require new controls to comply with specified provisions in §116.617, Standard Permits for Pollution Control Projects. The commission believes that relying on these existing procedures for the installation of controls will provide an efficient review process. The new §116.911(a)(3) specifies that, in cases where there are increased emissions from the addition of new controls, air dispersion modeling and/or ambient monitoring may be required to determine off-property impacts. TUC, §39.264(e) requires coal-fired EGFs to comply with the opacity limits specified in commission rules. Applicants must submit an application for an EGFP under the seal of a Texas licensed professional engineer, consistent with §116.110(e), concerning Applicability.

In response to comments, the commission deleted the references to federal rules and regulations in §116.911 and §116.913. This deletion will simplify the application process for EGFPs. However, EGFs must comply with any applicable federal requirements, including, but not limited to, nonattainment review, Prevention of Significant Deterioration (PSD) review, New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPS), and NESHAPS for Source Categories. EGFs that are affected sources under FCAA, §112(g), concerning Modifications, must comply with those requirements. The issuance of an EGFP does not modify or limit the applicability of these federal programs. If, during the review of an application for an EGFP the commission determines that the EGF is not in compliance with any applicable state or federal standards, the commission will initiate the appropriate enforcement action which may include a requirement to obtain an NSR permit or the applicable federal permit.

EGFs that are currently authorized under Chapter 116 may elect to participate in the EBTA under Chapter 101, Subchapter H, Division 2. The proposed §116.912 contained application requirements for electing EGFs that were in addition to those contained in the proposed §116.911. Those requirements are now in §116.911(b). Since an existing NSR permit may authorize multiple facilities, the permit application submitted under Subchapter I should identify which EGFs are to be included in the EGFP. The application must include documentation of the emissions from the 1997 Emissions Scorecard from the United States Environmental Protection Agency (EPA) Acid Rain Program, or if that information is not available, the actual emissions from that electing EGF for calendar year 1997. Applications must contain documentation of actual emissions as well as fuel consumption, fuel heating values, and heat input in MMBtu for calendar year 1997. This information will be used to calculate allowances for these EGFs and provide the data needed to meet the requirements of TUC, §39.264(i)(3), which restricts the banking and trading of allowances that result from reduced utilization and shutdown.

The new §116.912 was renamed "Electing Electric Generating Facilities." The proposed §116.912 contained the application content requirements for electing EGFs. These requirements were moved to the new §116.911(b). Section 116.912 now contains the requirements for opting in and out of the permitting program. An electing EGF may opt out of the requirements of this subchapter under certain conditions. The electing EGF must notify the commission of its intent to opt out prior to the beginning of the next control period and may not opt out during a control period. This notification requirement would prevent an EGF from opting out in order to avoid being out of compliance with the requirement to not exceed its allowances. The decision to opt out will become effective at the beginning of the control period following notification to the commission. All allowances for the electing EGF will be voided by the commission and may not be banked for subsequent use. Since the EGF would no longer be subject to the restrictions of the EBTA, it would be inappropriate to use those allowances at other EGFs, and no allowances will be allocated for subsequent control periods. Once an EGF has opted out, the EGF may not participate in the EBTA at any future date. Since TUC, §39.264 states that EGFs must elect to participate prior to September 1, 2000, there is not a subsequent opportunity for those EGFs to reelect. The commission believes that a one-time election and a one-time opt out provide sufficient flexibility without undermining the program. The owner or operator shall request an alteration to the electing facility's NSR permit to remove the conditions pertaining to the EGFP. This alteration would restore the NSR permit to its prior status.

The new §116.913 contains general conditions applicable to every EGFP unless specified differently in the permit, and authorizes the commission to include special conditions in the permit. An EGFP would authorize NO_x emissions from EGFs, and from coal-fired EGFs, SO_2 emissions and PM through opacity limitations. The EGF must comply with the EBTA in Chapter 101, Subchapter H, Division 2. In response to comments, former §116.913(a)(1)(C), concerning emissions of air contaminants other than NO_x, SO_2, and PM through opacity limitations from grandfathered EGFs, as defined in §116.10, concerning General Definitions, was reorganized and its provisions are now in §116.913(a)(2) and (3). An EGFP may permit emissions of all other air contaminants from grandfathered EGFs, provided the requirements of Chapter 116, Subchapter H are met. VERPs for grandfathered facilities as defined in §116.10 at sites with grandfathered or electing EGFs may be consolidated with an EGFP. The provisions for the EBTA require EGFs to maintain allowances in a compliance account. The EBTA in Chapter 101 contains all provisions for managing allowances. For emissions of NO_x and, where applicable, SO_2, the EGF shall hold in its account, on June 1 after every control period, a quantity of allowances equal to or greater than the amount of that air contaminant emitted since May 1 of the previous year. Holders of EGFPs shall comply with this requirement beginning May 1, 2004. Beginning May 1, 2004, holders of EGFPs must report annual actual emissions of NO_x and, if applicable, SO_2, for the previous control period. This emissions report must be submitted by June 30 of each year, and will be used to determine compliance with the requirement that the EGF hold allowances equal to or greater than the emissions over a given control period. The adopted section implements TUC, §39.264(e) and requires coal-fired EGFs to comply with the opacity limits specified in commission rules.

The new §116.914 specifies monitoring and reporting requirements for EGFPs, and the adoption was reorganized for clarity in response to comments. The commission is required by TUC, §39.264(k) to provide methods for use in determining compliance with permits and methods for monitoring and reporting actual emissions of NO_x and, if applicable, SO_2. Title 40 Code of Federal Regulations (CFR) Part 75, concerning Continuous Emission Monitoring Under the Acid Rain Program (Acid Rain Program), contains monitoring requirements for SO_2 for affected units under that program. Since the acid rain program already requires extensive monitoring, the adopted rule authorizes the use of that monitoring for EGFs that are subject to the acid rain program for compliance with Subchapter I. EGFs not subject to the Acid Rain Program would have three choices in monitoring. The EGF may choose to meet either Part 75 monitoring requirements, or the requirements of Title 40 CFR Part 60, or the EGF may provide an alternative monitoring plan that would be incorporated into the permit conditions. Part 60 requirements are adopted as an alternative to Part 75 in order to be consistent with current NSR practices for facilities not required to comply with Part 75. Since Part 60 monitoring may be less accurate than Part 75 monitoring, the adopted rule requires Part 60 monitored data to have a relative accuracy of greater than 10% (i.e., measured values within 90-100% of the correct value). To account for this inaccuracy, the monitored value must be multiplied by a factor of 1.1. This factor has been included to account for the inequity between the monitoring accuracy of Parts 75 and 60. The commission believes that this factor, proposed in the Ozone Transport Commission's (OTC) Model Rule, is appropriate for the EBTA as well, based on the similarity of the OTC requirements and the goals of TUC, §39.264. The OTC Model Rule implements a NO_x emission budget program to reduce ambient ozone concentrations. Although Texas is not required to participate in the OTC budget program, the commission believes that it is appropriate to model this budget rule after the OTC model rule. Additionally, EGFs with a heat input of less than 100 MMBtu/hour could use Appendix E of 40 CFR Part 75 to estimate NO_x emissions. Appendix E relies on stack testing of the facility to develop a relationship between the emission rate and heat input. The commission believes that it is appropriate to structure the monitoring requirements of Subchapter I on these existing requirements because many EGFs are currently using Part 75 and Part 60 monitoring methods. Data collected from these monitoring requirements would be used to calculate annual emissions that are reported to the commission for the purpose of demonstrating compliance with allowances. The new §116.914 also specifies that data collected from the monitoring of EGFs shall be detailed in an annual report as required under §116.913(a)(7). The commission will develop a form, AR-1, specifying the requirements of the report, which would be due on June 30 of each year.

The new §116.916, concerning Permits for Electric Generating Facilities in El Paso County, was renamed to "Permits for Grandfathered and Electing Electric Generating Facilities in El Paso County." Consistent with TUC, §39.264(q), §116.916 would exempt EGFs in El Paso County from NO_x allowance requirements if the commission or EPA determines that reductions in NO_x emissions would lead to increased ambient levels of ozone. Currently, NO_x reductions are not required for facilities in the El Paso nonattainment area because EPA has granted a waiver under FCAA, §182(f). Under this waiver, NO_x reductions are not required if the attainment demonstration for compliance with the ozone National Ambient Air Quality Standard (NAAQS) can be made without a NO_x control strategy. The existence of this waiver is not consistent with the provisions of TUC, §39.264(q) because it has not been demonstrated, under the §182(f) waiver or otherwise, that NO_x reductions would increase ambient ozone in El Paso County. These EGFs would still be required to obtain a permit under 30 TAC Chapter 116, Subchapter I regardless of the determination that NO_x reductions are counterproductive in controlling ambient ozone levels in the El Paso Region. The commission believes that this requirement is appropriate, since TUC, §39.264(e) provides that EGFs without a permit may not operate after May 1, 2003, and TUC, §39.264(q) refers only to reduction requirements, not permitting requirements. Regardless of this determination, grandfathered EGFs in El Paso County would still be required to obtain a permit under Subchapter I.

The new §116.920 would require that applicants for initial issuance of an EGFP publish notice of intent to obtain a permit in accordance with 30 TAC Chapter 39, Subchapter K, concerning Public Notice of Air Quality Applications. Subchapter K implements the new requirements of TCAA, §382.056, as amended by the 76th Legislature by House Bill (HB) 801, an act relating to Public Participation in Certain Environmental Permitting Procedures of the TNRCC. TUC, §39.264 provides that public participation for initial issuance of an EGFP will be done in the manner of TCAA, §382.0561, concerning Federal Operating Permit; Hearing; and TCAA, §382.0562, concerning Notice of Decision. These sections allow for notice and comment hearings instead of contested case hearings under Texas Government Code, Chapter 2001, and require the commission to send notice of final action to persons who comment during the comment period or during a hearing. The adopted requirements of §116.920, 116.921, and 116.922 are based on the sections in 30 TAC Chapter 122, concerning Federal Operating Permits, that implement the requirements of TCAA, §382.0561 and §382.0562. Section 116.920 provides that any person who may be affected by emissions from the EGF may request a notice and comment hearing on an EGFP application within 30 days after the publication of Notice of Receipt of Application and Intent to Obtain Permit under §39.418, concerning Notice of Receipt of Application and Intent to Obtain Permit. Grandfathered support facilities that elect to obtain a VERP and have it consolidated with an EGFP may publish a combined notice. Electing EGFs that are included in an EGFP are only included for the purpose of authorizing NO_x emissions, and if applicable, PM through opacity limitations and SO_2. The conditions of the electing EGF's existing NSR permit would be altered to cross-reference the EGFP. Since the rule was revised to require alterations to the electing EGF's existing NSR permit, the provision in §116.920(c), concerning public notice for emissions of air contaminants other than NO_x, or if applicable, SO_2, was deleted. The existing NSR permit conditions would not be subject to public notice. Any conditions in the EGFP concerning the electing EGFs would be subject to public notice. Persons affected by a decision to issue or deny an EGFP will be entitled to petition for a rehearing under the appropriate procedure in Chapter 50, concerning Action on Applications and Other Authorizations, and may seek judicial review under TCAA, §382.032, concerning Appeal of Commission Action. The commission made clerical changes to §116.920 to include references to grandfathered and electing EGFs and renumbered that section, since §116.920(c) was deleted. Section 116.920(g), now §116.920(f), was revised to clarify that a person affected by a decision of the commission to issue or deny an EGFP may seek judicial review. This change makes this subsection consistent with the language in §116.922(b)(3).

The commission made clerical revisions to §116.921 to add the terms "grandfathered" and "electing EGFs" as well as to delete references to draft permits and refer instead to draft EGFPs. The new §116.921 contains the hearing requirements for the initial issuance of EGFPs. The rule allows the commission to decide whether to hold a hearing based on the reasonableness of a request. The commission is not required to hold a hearing if the basis of the request by a person who may be affected by emissions from the grandfathered or electing EGF is determined to be unreasonable. If a hearing is requested by a person who may be affected by emissions from the grandfathered or electing EGF, and that request is reasonable, the commission will hold a hearing. The section requires that notice of hearing on a draft EGFP be published in the public notice section of one issue of a newspaper of general circulation in the municipality or the nearest municipality where the EGF is located. The notice must be published at least 30 days prior to a hearing. The notice is published at the applicant's expense and the rule specifies the content of the notice. The rule provides the procedures for the submittal of comments at a hearing and specifically states that the period for submitting written comments extends to the close of the hearing and may be extended beyond the close of the hearing. Any person, including the applicant, may submit comments on whether the draft EGFP contains inappropriate conditions or whether the preliminary decision to issue or deny the EGFP is inappropriate. Commenters shall raise all issues and submit all comments supporting their position by the end of the public comment period. This requirement will assist the commission in developing its response to comments as required by new §116.922. To ensure a complete record of the comments, the rule prohibits the incorporation by reference of supporting materials for comments unless the materials meet the criteria in §116.921(g). The commission is required to keep a record of all comments submitted or raised at a hearing and to have an audio recording or written transcript of the hearing, and the record is available to the public. Draft EGFPs may be revised based on comments pertaining to whether the permit provides for compliance with the requirements for an EGFP.

The new §116.922 was revised to include a reference to the draft EGFP. The new §116.922 requires the commission to individually notify persons who commented, either during the public comment period or at a permit hearing, of the final action of the commission. The notice must be sent by first-class mail to the commenters and to the applicant. The notice must include the response to comments, the identification of any changes in the permit, and a statement that any person affected by the decision of the commission may petition for rehearing under the appropriate procedure in Chapter 50, concerning Action on Applications and Other Authorizations, and may seek judicial review under TCAA, §382.032.

TUC, §39.264 does not provide procedures for the modification of an EGFP. The commission believes that the requirements of the TCAA concerning modifications of existing facilities still apply. Therefore, the new §116.930 requires that any modifications to any facility in an EGFP are subject to the permitting requirements of the TCAA and the existing modification requirements in 30 TAC Chapter 116, Subchapter B.

Consistent with TUC, §39.264(r), the new §116.931 requires EGFPs to be renewed under the requirements of 30 TAC Chapter 116, Subchapter D, concerning Permit Renewals. The commission made a clerical revision to this section to delete the abbreviation of EGFP.

FINAL REGULATORY IMPACT ANALYSIS

The commission has reviewed the rulemaking in light of the regulatory analysis requirements of Texas Government Code, §2001.0225, and has determined that the rulemaking meets the definition of a "major environmental rule" as defined in that statute. "Major environmental rule" means a rule the specific intent of which is to protect the environment or reduce risks to human health from environmental exposure, and that may adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, or the public health and safety of the state or a sector of the state. The adopted amendments to Chapter 116 are intended to protect the environment or reduce risks to human health from environmental exposure and may have adverse effects on grandfathered and electing EGFs which could be considered a sector of the economy. However, the analysis required by §2001.0225(c) does not apply, because the adopted amendments do not meet any of the four applicability requirements of a major environmental rule. The new sections do not exceed a standard set by federal law, exceed an express requirement of state law, or exceed a requirement of a delegation agreement, and they are not adopted solely under the general powers of the agency. The amendments to Chapter 116 are adopted specifically to implement TUC, §39.264. TUC, §39.264 requires grandfathered EGFs apply for a permit by September 1, 2000, and obtain a permit by May 1, 2003, or cease operating, absent a showing of good cause to continue operating. The adopted amendments allow the permitting of all other air contaminants for grandfathered EGFs using the VERP process. Support facilities may be permitted under a VERP which may be consolidated with an EGFP. There is no federal law or delegation agreement with a federal agency that requires the permitting of grandfathered EGFs.

TAKINGS IMPACT ASSESSMENT

The commission has completed a takings impact assessment for the adopted rules. The following is a summary of that assessment. These new sections implement the requirements of TUC, §39.264. This section requires owners or operators of grandfathered EGFs to apply for a permit on or before September 1, 2000, and obtain a permit or cease operation by May 1, 2003. It is the intent of §39.264 that for the 12-month period beginning May 1, 2003, and for each 12-month period following, annual emissions of NO_x from grandfathered EGFs not exceed 50% of the NO_x emissions reported to the commission for 1997. Furthermore, it is the intent of the legislation that emissions of SO_2 from coal-fired EGFs not exceed 75% of the SO_2 emissions reported to the commission in 1997. NO_x and SO_2 allowances will be allocated to EGFs by January 1, 2000. To assist EGFs in meeting the reduction requirements, a banking and trading program is adopted concurrently in Chapter 101. Although EGFs are required to make specific emission reductions, these facilities have alternatives available under the banking program that may allow the EGF to avoid installing add-on controls. Further, allowances can be transferred under the banking program so that EGFs have opportunities to buy and sell allowances in order to respond to business needs. The new sections do not affect private property in a manner that restricts or limits an owner's right to the property that would otherwise exist in the absence of the governmental action. Consequently, this adoption does not meet the definition of a takings under Texas Government Code, §2007.002(5). The reductions obtained from the issuance of EGFPs will assist in the efforts of the commission to attain the NAAQS. This action is taken in response to a real and substantial threat to public health and safety and significantly advances the health and safety purpose and imposes no greater burden than is necessary to achieve the health and safety purpose.

COASTAL MANAGEMENT PROGRAM CONSISTENCY REVIEW

The commission has determined that this rulemaking relates to an action or actions subject to the Texas Coastal Management Program (CMP) in accordance with the Coastal Coordination Act of 1991, as amended (Texas Natural Resources Code, §§33.201 et seq.), and the commission's rules in 30 TAC Chapter 281, Subchapter B, relating to Consistency with Texas Coastal Management Program. As required by 31 TAC §505.11(b)(2) and 30 TAC §281.45(a)(3), relating to actions and rules subject to the CMP, commission rules governing air pollutant emissions must be consistent with the applicable goals and policies of the CMP. The commission has reviewed this action for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council. For the new sections related to the authorization of EGFPs, the commission has determined that the rules are consistent with the applicable CMP goal expressed in 31 TAC §501.12(1) of protecting and preserving the quality and values of coastal natural resource areas, and the policy in 31 TAC §501.14(q), which requires that the commission protect air quality in coastal areas. This adoption is intended to reduce overall emissions of NO_x and, if applicable, SO_2 from grandfathered EGFs. This action is consistent with 40 CFR because it does not authorize an emission rate in excess of that specified by federal requirements.

PUBLIC HEARING AND COMMENTERS

The commission conducted public hearings concerning this adoption in El Paso and Lubbock on October 1, 1999, in Austin on October 4, in Irving on October 5, in Houston on October 7, and in Beaumont on October 7.

The following submitted written comments or provided testimony during the public comment period which closed on October 11, 1999: EPA-Acid Rain Division (EPA-ARD); EPA-Clean Air Markets Division (EPA-CAMD); EPA-Air Permits Division (EPA-APD); EPA-Air Planning Section (EPA-APS); The University of Texas System, Office of General Counsel (UT); Enron, Central and South West Services, Inc. (CSW); TXU Business Services (TXU); Brazos Electric Power Cooperative, Inc. (Brazos); Baker & Botts, L.L.P.-Texas Industry Project (Baker & Botts); Clark & Seay, L.L.C. (Clark & Seay); Southwestern Public Service Company (SPS); Entergy Gulf States, Inc./Entergy Texas (Entergy); El Paso Electric Company (EPE); Lloyd, Gosselink, Blevins, Rochelle, Baldwin & Townsend, P.C.-City of Garland (Lloyd Gosselink); League of Women Voters of Texas (LWV-TX); The Center for Energy and Economic Development (CEED); Association of Electric Companies of Texas, Inc. (AECT); Reliant Energy (Reliant); Entergy Services Inc. (Entergy Services); Environmental Defense Fund (EDF); City of Austin/Austin Energy (AE); Sustainable Energy and Economic Development Coalition (SEED); Public Citizen, Texas Clean Water Action, Texas Communities Project (PC); City Public Service of San Antonio (CPS); Bracewell & Patterson (B&P); Lubbock Power & Light & Water (LP&L); Clark, Thomas & Winters (CT&W); Central & South West, City of Austin, City Public Service, El Paso Electric, Entergy, Reliant Energy, Southwestern Public Service, and TXU (Group A); (Group A); Mothers for Clean Air (MCA); Neighbors for Neighbors (NFN); and 17 individuals.

ANALYSIS OF TESTIMONY

One individual commented that the commission should exercise its authority to require significant reductions at power plants in East Texas, with another individual adding that the reductions should be permanent. Three individuals stated that the commission should enforce reduced emissions from grandfathered electric generating facilities, and two more individuals added that the commission should be as strict as possible in that enforcement.

While this adoption addresses grandfathered EGFs only, the commission is developing rules that will apply NO_x restrictions on all EGFs in the East Texas Region. The specific level of emissions required from these facilities will be determined on computer analysis that indicates what reductions should be required to assist the affected nonattainment areas in meeting the NAAQS. The net reductions required under this adoption are permanent. The commission will exercise its full enforcement power as authorized by statute, rule, or as governed by enforcement policy. This adoption requires mandatory permitting for emissions of NO_x and, if applicable SO_2 and PM through the commission's opacity standards, the rules provide options for the permitting of other air contaminants from grandfathered EGFs.

Four individuals stated that the commission should seek improvements that address SO_2, particularly to improve visibility in Big Bend. Another individual added that the commission must require a larger NO_x and SO_2 reduction to reduce acid rain and ozone in Texas nonattainment areas.

In cooperation with EPA and the National Park Service, the commission is analyzing the nature and location of required reductions to address reduced visibility in Big Bend National Park. This analysis is incomplete and therefore, the commission believes that requiring reductions specifically to the Big Bend area prior to the completion of this analysis is premature. The authority granted to the commission under TUC, §39.264 and other existing authority allows the commission to seek additional reductions in SO_2 as needed. As stated previously, the commission is addressing additional NO_x reductions that may be required to assist in the attainment of the NAAQS in a separate rulemaking. There are no areas in Texas that are nonattainment for SO_2, and the commission is not aware of any areas that are adversely affected by acid rain.

One individual stated that the commission should not allow a cap and trade or banking system because it avoids environmental justice issues and perpetuates emissions in low-income areas. The same individual suggested that the exclusion for individual units to be regulated under TUC, §39.264 be lowered to ten megawatts from 25 megawatts. This individual also stated that the commission estimate of cost of compliance with the requirements of the adoption is low, and it appears that the commission is allowing low-grade technology to be applied to the regulated units.

The trading and banking provisions of this adoption are required elements of the reduction program under TUC, §39.264. SB 7 provides that total annual emissions of NO_x from grandfathered EGFs will not exceed 50% of the NO_x emissions in 1997 as reported to the commission and that for coal-fired grandfathered EGFs, the total annual emissions of SO_2 will not exceed 75% of the emissions during 1997, as reported to the commission. SB 7 also provides that the trades of allowances will only occur within the same region, either East Texas, West Texas, or El Paso. The effect of this will be an overall 50% reduction in NO_x and a 25% reduction in SO_2 within the region. SB 7 does not require a specific level of reduction at any individual grandfathered EGF. The exemption level for individual generating units of 25 megawatts is specified in TUC, §39.264(d). As discussed elsewhere in the adoption preamble, the commission has also excluded EGFs that generate power primarily for internal use, but that during 1997 sold one-third of their generated power or less than 219,000 megawatt-hours to the utility power distribution system. The commission believes that excluding these EGFs is consistent with SB 7 and will not negatively affect the overall emission reductions required by the program. Lowering the exemption to ten megawatts will require small generators to participate in the EBTA and permitting program and will achieve little environmental benefit in relation to the cost of compliance with the program. The commission has based its estimate of the cost of applying control technology to attain the 0.14 pound per MMBtu on the February 1999 joint Public Utility Commission of Texas (PUCT) and TNRCC report, *Electric Restructuring and Air Quality: A Preliminary Analysis of Reductions and Costs of Nitrogen Oxides Controls from Electric Utility Boilers in Texas.* The estimate does not limit the amount EGFs must spend to meet the EBTA and accounts for technology of necessary sophistication to meet the requirements of this adoption.

The Honorable Lon Burnam, State Representative, District 90, commented concerning the implementation of SB 7 and its impact on consumers from an economic perspective. Mr. Burnam expressed his concerns that the commission implement the provisions of SB 7 free from the influence of lobbyists. Mr. Burnam urged the commission to consider public health in the process of implementing SB 7.

The provisions of SB 7 concerning deregulation of the electric industry will be implemented by the PUCT. The commission conducted six hearings in order to seek the public comment of citizens, the regulated community, and environmental groups. The hearings were conducted in El Paso, Lubbock, Austin, Irving, Houston, and Beaumont. Prior to proposal, the commission held a stakeholder meeting to seek input from interested persons. Notice of this meeting was provided on the commission's web page. In addition, pre-proposal drafts of the rules were posted on the commissions's web page with a request for comments. The commission believes that the adopted rules are consistent with SB 7 and remains committed to implement the program in a fair and impartial manner. Since EGFs are being permitted under the requirements of TUC, §39.264, which does not require a health effects review, no review is included in this adoption. The commission believes that this program will reduce ambient levels of NO_x and SO_2 and improve the overall air quality of the state. These reductions will assist the commission in its efforts to attain the health-based NAAQS.

Clark & Seay and MCA commented that all power plants that are in or near an area with unsafe air should be required to meet the 0.14 pounds/MMBtu standard used in federal laws and to the level to which all grandfathered plants will be required to be cleaned up. In addition, LWV-TX commented that the rules in general be expanded to require all power plants that are in areas with unsafe air or that contribute to those nonattainment areas meet the same standard.

This adoption implements the requirements of TUC, §39.264 and application of this statute is limited to grandfathered EGFs and those EGFs that elect to participate in the permitting and trading program. The intent of SB 7 is not to achieve attainment with the NAAQS, but to permit and reduce emissions from grandfathered EGFs. While the implementation of SB 7 will provide emission reductions in areas near grandfathered EGFs, the commission recognizes that it will likely be necessary to adopt rules that will require air pollution control in attainment areas as well as additional rules for nonattainment areas. These controls would not only apply to emissions of NO_x from grandfathered EGFs, but permitted EGFs and other sources of NO_x as well. Further, specific emission rates will be established that have been determined necessary to meet air quality standards. Rules implementing these additional controls are scheduled for proposal in late 1999 or early 2000. The commission is not aware of any federal standards that require EGFs to meet a NO_x emission restriction of 0.14 pounds/MMBtu.

EDF commented that TUC, §39.264(n)(1) includes two specific penalties for facilities that exceed their allowances. The commenter noted that the proposed rules did not include any administrative penalties, and recommended that they be added at a level sufficient to deter noncompliance. EDF recommended three times the current market value of allowances.

The commission does not typically address the amount of administrative penalties in specific rules. Rather, penalty amounts are established in accordance with the commission's penalty policy. All enforcement cases not referred to the Office of the Attorney General go through staff preparation of an administrative penalty recommendation in accordance with the commission's penalty policy. Staff obtains an agreement or litigates to obtain an order against the respondent that requires the payment of penalties. The commission determines the amount of the penalty in accordance with the commission's enforcement rules and penalty guidance. The statutory language requires "enforcing an administrative penalty" and not "assessing" an administrative penalty.

Reliant requested that the published list of grandfathered EGFs be revised by deleting the Cedar Bayou Units 1 and 2 (Account Number CI-0012-D) because the units are no longer grandfathered and are permitted under Permit Number 1532. In addition, Reliant provided heat input information for facilities that were missing from the proposed list. CPS commented that V.H. Unit 1 should be corrected from 2,946,936 MMBtu to 2,949,512 MMBtu, as was submitted to EPA in the Acid Rain Database.

The commission will make these corrections to the list entitled "Nitrogen Oxide and Sulfur Dioxide Allowances for Grandfathered Electric Generating Facilities."

EPE commented that the language in TUC, §39.102(c) and §39.264(i) illustrate EPE's exemption from Chapter 39 and EPE's ability to elect to designate a facility to become subject to §39.264 and they noted that EPE is a "person" under PURA.

The commission agrees that EPE is a "person" under the TUC. The commission has not revised the rule to exempt EPE from the program requirements. TUC, Subchapter C, Retail Competition, §39.102, concerns retail customer choice, and exempts from TUC Chapter 39, any electric utility that has a system-wide freeze for residential and commercial customers that is in effect from September 1, 1997 and extends beyond December 31, 2001, that has been found by a regulatory authority to be in the public interest. Subchapter C also contains §39.264, which requires any EGF that existed on January 1, 1999, that is not subject to the requirement to obtain a permit under TCAA, §382.0518(g), to apply for and obtain a permit from the commission.

Section 39.264 was added to SB 7 during the final weeks of the 76th Legislative Session. Its very specific intent is to require grandfathered EGFs to obtain a permit from the commission and to obtain reductions of NO_x and SO_2 in the regions as defined by the bill. TUC, §39.264 contains several specific references to the El Paso area that make it clear that the Legislature intended EGFs in that area to be subject to the permitting and allowance program. TUC, §39.264(g) requires the commission to develop rules that define the "El Paso Region." TUC, §39.264(h) specifies an emission rate for the El Paso Region. TUC, §39.264(p) specifically requires the commission to develop rules to allow EGFs in the El Paso Region to meet emissions allowances by using credits from reductions made in Ciudad Juarez, United States of Mexico. Finally, TUC, §39.264(q) allows the commission to exempt EGFs in the El Paso Region if the commission determines that reductions in NO_x would result in an increased amount of ambient ozone levels in El Paso County.

The Code Construction Act, §311.021, Texas Government Code, provides that "In enacting a statute, it is presumed that: (1) compliance with the constitutions of this state and the United States is intended; (2) the entire statute is intended to be effective; (3) a just and reasonable result is intended; (4) a result feasible of execution is intended; and (5) public interest is favored over any private interest." If TUC, §39.102 were read to exclude EGFs in the El Paso Region from the provisions of Chapter 39, the specific provisions of TUC, §39.264, concerning the El Paso Region, would be rendered ineffective. As prescribed by the Code Construction Act, the commission must interpret the provisions of Chapter 39 so that all sections can be given effect. To do otherwise would contravene the intent of the Legislature. Thus, the commission agrees that EPE is exempt from the provisions regarding customer choice in TUC, Chapter 39. However, if EPE were exempted from the permitting and EBTA requirements, the provisions of TUC, §39.264, concerning the El Paso Region, would be meaningless. The commission agrees that EPE may use the provisions of §116.912, concerning Electing EGFs.

Lloyd Gosselink commented that the rules do not address the use of oil as a backup fuel at a gas- fired facility. The commenter stated that under certain curtailment situations, gas may not be available, and gas-fired facilities may be required to switch to oil as a fuel source, and that under these conditions, facilities should not be penalized for any additional NO_x emissions.

The commission believes that a facility has the latitude to use any fuel as long as actual emissions comply with its allotted allowances, and the use is authorized by the appropriate NSR authorization. The commission does not believe it is appropriate to revise the rules to include an exception to exceed allowances in the case of a curtailment because SB 7 does not allow for this exception. If a curtailment occurs, and emissions of NO_x exceed an EGF's allowances, the commission will rely on its enforcement policy to determine the appropriate response. Use of previously unused fuels may constitute a modification and require an NSR permit. The rules have not been revised in response to this comment.

LWV-TX commented that the TNRCC should restrict pollution trading in ways that assure significant reductions in air pollution.

SB 7 requires the commission to allocate allowances to grandfathered EGFs in defined regions of the state. The specific intent of SB 7 is that total annual emissions of NO_x from grandfathered

EGFs will not exceed 50% of the NO_x emissions in 1997 as reported to the commission and that for coal-fired grandfathered EGFs, the total annual emissions of SO_2 will not exceed 75% of the emissions during 1997, as reported to the commission. The adopted rules provide the requirements for both the permitting of these grandfathered EGFs, and an emission banking and trading program. Both of these programs are critical to the successful reduction of the NO_x and SO_2 emissions contemplated by SB 7. The EBTA contains restrictions on trading that will ensure that the required emission reductions are enforceable. The commission believes that the required reporting and monitoring, along with the statutorily defined enforcement provisions, will ensure that the program achieves the reductions intended by TUC, §39.264. The commission believes that the implementation and enforcement of the adopted rules will ensure that the reductions mandated by SB 7 occur and that no modification to the rule is necessary.

CEED commented that the preamble referenced adopting additional requirements for EGFs in nonattainment areas, indicating further reductions of 88% in Dallas/Fort Worth (DFW) and 90% in Houston/Galveston (HGA) areas. The commenter stated that the emissions inventory shows that these point sources only represent a minor source of NO_x emissions, since the majority of emissions are generated by on-road and off-road mobile and area sources, and that the inclusion of these statements regarding the further need to reduce emissions from EGFs continues to focus attention on sources which will not solve nonattainment problems in these areas. CEED also commented that the proposal preamble statements that EGFs must consider local impacts of allowance transfers and that "EGFs emit significant amounts of NO_x, which has been shown to heavily influence local ozone levels" are comments without any qualifications to specific EGFs and perpetuate the opinion by some that all EGFs emit significant levels of emissions. CPS supports the removal of all references to SIP requirements from the SB 7 regulations. An example is on page 7140 of the proposal preamble, where it states that "...EGFs must consider local impacts of allowance transfers...." Furthermore, the preamble states that "These EGFs (in near-nonattainment areas) emit significant amounts of NO_x which has been shown to heavily influence local ozone levels." CPS disagrees which this statement. First, the mandatory SB 7 program was designed to be flexible, and allow reductions to be made in the most cost-effective manner. Second, the utility plants in San Antonio, owned by CPS, do not contribute heavily to local ozone levels, as indicated by previous modeling performed by Alamo Area Council of Governments under the direction of the TNRCC. Therefore, TNRCC's concern that SB 7 allowance trading will jeopardize the regional strategy is unwarranted, at least for the near-nonattainment area of San Antonio.

The reductions mandated by SB 7 only apply to grandfathered EGFs in the defined regions of Texas. These reductions from grandfathered EGFs will be significant; however, it is unlikely that the reductions will be sufficient to address the need to further reduce emissions in both attainment and nonattainment areas. The commission believes that to achieve attainment with the NAAQS, it will be necessary to reduce emissions from all sources, both stationary and mobile, in both attainment and nonattainment areas. The reductions that will be achieved under the adopted rules will be significant towards reaching attainment. In addition, the commission believes that NO_x emissions from EGFs are not minor, but significantly contribute to ground-level ozone formation. The preamble comments regarding the potential impacts of trading on near-nonattainment areas were included to recognize that emissions in near- nonattainment areas may have a negative impact on that areas ability to remain in attainment. Emission inventory information indicates that NO_x emissions from EGFs are approximately 47% of the stationary source NO_x emissions in the East Texas Region.

EPA-CAMD commented that the cost effectiveness numbers of $4,000 per ton of NO_x removed in the absence of emissions trading, or $2,000 per ton of NO_x removed with emissions trading, seem far too high. For example, in the May 25, 1999 Final Rule under §126 of the FCAA (64 FR 28300), EPA determined an average cost- effectiveness of $1,468 per ton of NO_x removed from electric generating units greater than 25 megawatts with emissions trading. Estimates for cost effectiveness of NO_x control under Ozone Transport Committee NO_x Budget Program range from $950- 1,600 per ton. Furthermore, the commenter noted that some gas-fired units can achieve an average NO_x emission rate of 0.14 lb/MMBtu simply using combustion controls.

The commission supports the preamble language. The listed values were based on information developed for the joint Public Utility Commission of Texas (PUCT) and TNRCC report published in February 1999, entitled *Electric Restructuring and Air Quality: A Preliminary Analysis of Reductions and Costs of Nitrogen Oxides Controls From Electric Utility Boilers in Texas.* For simplicity in the report, the costs of emission reductions were analyzed on a unit-by-unit basis. Thus, the potential for "over-compliance" for certain generating units in cases where it may be more cost-effective was not captured in the analysis. A subcommittee of the Ozone Transport Assessment Group (OTAG) has analyzed market-based emission trading options, such as the EBTA, estimating potential savings of as much as 50%, compared to the costs of unit-by-unit compliance. This analysis is applied to all utility generating units in the state, which may overstate the magnitude of the estimated compliance costs. The commission believes that, in practice, the costs of permitting and participation in the EBTA will be much less that what was estimated in the proposal.

EPA-APD commented on its understanding that the TNRCC will use emission reductions which occur under these regulations to help demonstrate attainment and maintenance of NAAQS. The commenter further understood that the reductions will not be used for offsets and netting under NSR. With this understanding, EPA-APD supported the adoption of these regulations if the TNRCC adequately addresses the remaining comments.

The EBTA and EGFP programs will be submitted as a revision to the SIP. The resulting reductions will be used by the commission to further its attainment goals. Allowances cannot be used to satisfy emission offset requirements under federal NSR; thus, they will not be used as netting for PSD or for offsets under a nonattainment NSR permit.

EPA-APD asked whether standard permits will be incorporated into a facility's federal operating permit through 30 TAC Chapter 122's permit modification provisions. AE recommended that once an EGFP is issued, any needed revisions to the site's federal operating permit (FOP) should be automatically incorporated as administrative corrections and not require an additional public comment period associated with changes to the FOP.

The commission does not anticipate developing a standard permit for use by grandfathered EGFs for the purpose of complying with TUC, §39.264. However, a grandfathered EGF is not prohibited from using any of the standard permits that are currently available. At this time, the commission's FOP program does not include the commission's NSR program as an applicable requirement. Only PSD, nonattainment permits, and case-by-case maximum available control technology (MACT) review under FCAA, §112(g) or (j), are required to be included in a FOP as applicable requirements. If and when the EPA determines that the commission's NSR program is an applicable requirement, holders of FOPs may be required to include references to standard permits in their FOP. If a FOP must be revised to address changes to applicable requirements as a result of the EGFP, then, depending on the nature of the revision, the appropriate revision process under Chapter 122 would be used.

PC recommended substituting renewable energy for electricity or energy used at a grandfathered facility, stating that this could provide a low cost way to reduce emissions and result in the building of additional new clean energy sources. The commenter stated that concurrent rulemaking at the PUCT to implement the renewable portfolio standard in SB 7 has resulted in the development of capacity factors and other evaluation procedures that can be useful to the commission in converting renewable capacity to energy for purposes of calculating avoided emissions and provide for a periodic update for that factor. PC stated that these rules developed by the PUCT should be incorporated by reference into the commission's rules.

The purpose of this rulemaking is to obtain emissions reductions from EGFs based on the specific provisions of SB 7; in particular, the 50% NO_x reductions and the 25% SO_2 reductions, if applicable. These reductions are to be made based on certain emission rates set forth in TUC, §39.264(h). It is possible that a grandfathered or electing EGF could make reductions relying on the use of renewable energy and that the factors developed by the PUCT may be used to evaluate such a proposal. Since the commission can consider the rules of the PUCT among many sources of information to make such decisions, the commission does not believe it is necessary to incorporate the PUCT rules into Chapter 101 or 116. The commission agrees that using renewable energy to achieve emission reductions is a viable option and one that might result in cost savings to certain facilities. As the commission continues to develop the permitting and EBTA programs, issues concerning renewable energy can be considered. In addition, if a grandfathered or electing EGF substitutes renewable energy, the resulting emissions should be lower, requiring less allowances for compliance, thus creating an economic incentive.

PC believes that the proposed rules will fail to assure that emissions are actually reduced. PC believes that the utilities are unlikely to offer a reduction at any plant other than those that are oldest and used the least. Many of these plants are permitted as base-load plants which operate 60-80% of the time, but are kept only for peak use and are used infrequently, less than 20% of the year. Thus, a facility might be glad to modify its permit by reducing permitted emissions that it would never really produce. PC recommends that the rule should be modified to require permit reductions based on the last five years of actual emissions.

The commission believes that the specified emission rates in the statute and the corresponding rules will achieve the target reductions. The intent of SB 7 is to achieve overall reductions of 50% NO_x emissions and 25% SO_2 emissions. An electing EGF would receive allowances equal to actual 1997 emissions, not permit allowable emissions, and would only be able to generate surplus allowances by reducing emissions below actual 1997 levels. Also, an electing EGF may not transfer or bank allowances that are conserved as a result of reduced utilization or shutdown unless the reduced utilization or shutdown results from the replacement of thermal energy from the electing EGF with thermal energy generated by any other EGF. Further, since SB 7 provides that 1997 is the base year for determining reductions, the commission does not believe it has the authority to require permit reductions based on the last five years of actual emissions. Therefore, the commission has not changed the rules in response to this comment. Therefore, the commission has not revised the rule in response to this comment.

PC commented that the rules adopted for the implementation of SB 7 should be structured in such a way as to allow the purchase and retirement of NO_x allowables issued under the SB 7 program to be used as project emission reduction credits under SB 766. PC recommended two alternatives. First, the TNRCC could allow a retail electric provider (REP) to sell renewables to the owner of a grandfathered facility and assume that there will be a reduction in emissions per megawatt hour (MW) at the average rate of emissions per MW for the power plants in the area. The commenter stated that this is the least costly way to assure that the program will work, and since Texas is effectively an isolated electrical grid, will assure that emissions are reduced in the state. The EPA has recognized the OTAG debates that add-on units that produce solar electricity or solar water heaters mitigate emissions. PC argued that a wind turbine, a solar water heater, or gases from landfills can similarly be rated based on capacity, converted into energy, and emissions reductions could thus be calculated. Secondly, TNRCC could allow the REP to buy and retire NO_x credits from the SB 7 trading program established in Chapter 101. This will assure that the emissions are actually reduced in the 60-county east Texas airshed, but it would add to the cost. The commenter further stated that since the transaction is on the open market, it may be far less costly than permit emission reductions purchased from the competitor; and the commission can significantly reduce the cost of the renewable energy used in the program by declaring that the renewable plants built to meet a contracted load under this program are pollution control devices as defined in Health and Safety Code, Chapter 383. If renewable energy installations are certified under Health and Safety Code, §383.004, the certification will exempt the owners from property taxes and allow them to qualify for pollution abatement bonds issued by local governmental units as provided by Health and Safety Code, §383.021. The combination of these two financial benefits could erase the premium price of renewable energy and make it the most cost-effective way to reduce emissions.

The commission will explore whether it has the authority to declare a renewable energy source, such as wind power, to be a pollution control device for the purposes of property tax exemptions and pollution abatement bonds. As the EBTA and permitting programs continue to develop, the commission can consider issues such as the use of add-on units that produce solar electricity or solar water heaters to reduce emissions. The commission agrees that REPs can buy and retire SB 7 allowances under Chapter 101 and that this transaction might be approved for use as a project emission reduction credit under the VERP program established by SB 766, as long as those allowances are not used to meet the requirements of SB 7.

One individual commented that health effects reviews should apply not only for grandfathered plants, but secondary sources as well.

The rules were not revised in response to this comment. The permitting program required by TUC, §39.264 does not include a health effects review. Emissions from grandfathered EGFs other than NO_x, and for coal-fired EGFs, SO_2 and PM may be permitted using the VERP program requirements. If an owner or operator chooses to permit grandfathered support facilities at sites with EGFs, the owner or operator may submit an application for a VERP under Chapter 116, Subchapter H. The VERP program provides for a health effects review.

One individual commented that companies have been grandfathered long enough and that the commission should tighten permitting regulations. SEED and two individuals commented that grandfathered energy producers should undergo a health effects review.

Since EGFS are being permitted under the requirements of TUC, §39.264, which does not require a health effects review, no review is included in this adoption. The commission believes that this program will reduce ambient levels of NO_x and SO_2 and improve the overall air quality of the state. These reductions will assist the commission in its efforts to attain the health-based NAAQS.

MCA commented that all grandfathered power plants should meet today's BACT or the federal NSPS for pollutants such as CO, SO_2, PM, and VOCs, and that this is especially important in areas such as the HGA region where there is not yet a demonstration of compliance with the ozone standard and where the area is bordering violation of the PM standard. NFN and LWV-TX commented that all grandfathered power plants should meet today's BACT or the federal NSPS if they are located in nonattainment areas or east of IH-35 and north of IH-37. Ten individuals commented that all grandfathered plants east of I-35 and north of I-37 must be required to use BACT or NSPS for pollutants such as CO, particulate, and VOC. One individual also recommended that the rules require grandfathered power plants to meet BACT or NSPS for other pollutants, as well as CO, PM_{10}, and all fluoro-organic compounds. Three individuals commented that grandfathered plants should use BACT. One individual commented and supported the comments of SEED and other environmental groups targeting power plants, and suggested that the commission require BACT for power plants in the Metroplex area, require compliance with federal laws, and use a wide net in a wide geographic area, since pollution comes from sources far away from Dallas. Two individuals added that the commission should require reductions in CO and VOC as well as NO_x and SO_2, with one stating that control of radioactivity should also be included in the adoption. One commenter stated that the commission should allow no emissions of NO_x, VOC, or particulate greater than any United States-built power plant.

The commission has made no changes in response to these comments. SB 7 does not prescribe specific control requirements. However, the commission notes that all EGFs must comply with any applicable NSPS and other federal standards. The use of BACT is only required if a grandfathered EGF is modified, consistent with the state or federal definition of "modification." EGFs applying for a permit under these adopted rules that do not initiate a modification to the EGF will only be subject to the specific reduction requirements of TUC, §39.264.They are required to achieve the 50% reduction in NO_x or the 25% reduction in SO_2, whichever is applicable, or meet the reduction requirements through the EBTA. TUC, §39.264 does not specifically require reductions or permitting of other pollutants; however, the adopted rules allow for the permitting of other air contaminants using the control technology and review process established in Chapter 116, Subchapter H, concerning the VERP program for grandfathered facilities.

In addition, SB 7 did not distinguish between grandfathered EGFs located in nonattainment areas versus attainment areas, nor does it require BACT or NSPS if an EGF is located in a nonattainment area. The commission has rules that address emissions from facilities in nonattainment areas, including EGFs and will be proposing additional rules that will require emission reductions from EGFs in both nonattainment and attainment areas east of IH-35 and east of IH-37. The commission will propose rules that address power plants and other sources in the DFW area and eastern Texas that will consider the effects of transport.

PC urged the commission to reduce emissions for all power plants in the 60-county Texas Clean Air Strategy area to no more than 0.10 pounds/MMBtu for coal and 0.06 pounds/MMBtu for natural gas plants. PC noted that the commission estimated in its February 1999 study that if these standards were adopted, NO_x emissions would drop by 96,000 tons per year. PC commented that the commission should propose rules at the earliest possible opportunity that require emission reductions in the 60-county area east of IH-35 and north of IH-37 to 0.14 pounds/MMBtu because data from the commission and from OTAG documents that this is the most cost-effective way to reduce ozone emissions in the state and is less costly than other options being considered, like inspection and maintenance and reducing emissions from grandfathered facilities or reformulating gasoline or buying low emission vehicles. If the commission were to enact this standard, PC estimates that an additional 80,000 tons per year of NO_x would be removed from the airshed. PC stated that the 0.14 pounds/MMBtu standard was assumed by the Legislature for the grandfathered facilities and had it been in place during the ozone season of 1997 and 1998, PC believes that 40-70% of the ozone exceedances in DFW could have been avoided. PC added that a level of 0.05 pounds/MMBtu would reduce even further the emissions from grandfathered units. Six individuals commented that all power plants should be required to meet the 0.14 pounds/MMBtu standard for NO_x.

Before the end of 1999, the commission will propose rules and additional amendments to the SIP that require reduction in NO_x emissions for permitted electric generating utilities and other industrial sources. The reductions are intended to reduce the amount of ozone and ozone precursor gases transported into DFW and other nonattainment areas. These rules will be proposed concurrently with several other rules as part of a program to reduce NO_x in the eastern portion of Texas. The commission has identified mobile sources as significant contributors to ozone levels, particularly in DFW, and intends to require reductions from these sources as well. The SIP amendments will target significant emission sources and require NO_x reductions where they will be most effective and do not unnecessarily burden a particular segment of the economy. The specific NO_x emission limits are also established according to these goals. The reductions achieved under the adoption of these rules implementing SB 7 will also be a part of this program.

SEED and PC commented that SB 7 must be read broadly to require the creation of a *de novo* permitting standard that at least provides for parity between Texas-grandfathered plants and new plants built today. SB 7 strictly indicated that the Legislature's intent was to remove special historical exemptions for older power plants to eliminate unfair competitive advantages and excess pollution, and that in SB 7, the Legislature intended that grandfathered units face the same permitting hurdles as those faced by new plants built today. TUC, §39.264(e) requires that grandfathered units must apply for *de novo* permits on or before September 1, 2000. TUC, §39.264(f) requires the TNRCC to develop rules for this permitting process. TUC, §39.264(g)-(j) instructs the TNRCC to also develop a system for allowances for sulfur and nitrogen emissions and set forth specific starting allowance formulas. The commenters stated that nowhere did the Legislature indicate that the TNRCC should not exercise its general organic authority in existing regulatory framework in reviewing and acting upon these *de novo* permit applications. The Legislature went even further and stated that it does not intend to "limit the authority of the TNRCC to require further reductions of nitrogen oxides, sulfur dioxide, or any other pollutant from generating facilities subject to" the law. Additionally, the Legislature provided for stranded cost recovery of unit cleanup costs. Finally, the Legislature also authorized cost recovery where the "amount and location of resulting emission reductions is consistent with the air quality goals and policies of the TNRCC." The commenters also stated that *de novo* permitting of grandfathered facilities should include at least NSR for NO_x and SO_2 as well as appropriate limits for air toxics and mercury, and that grandfathered facilities should at least meet the NSR performance requirements that would have to be met by new coal or gas plants sited in Texas today. Reasons for this include concerns with ozone, nitrogen enrichment in estuaries, acid deposition, haze, PM2.5, and mercury and other hazardous air pollutants. SEED included health effects and coal combustion wastes. PC commented that, in particular, the rules should provide that EGFs be treated as would any new coal, oil, or gas power plant applying for *de novo* permitting. At a minimum, the TNRCC should thus require EGF's seeking permitting under the rules to meet BACT or lowest achievable emission rate (LAER) standards for NO_x and SO_2 depending on whether the units are located in an attainment or nonattainment area. In addition, the TNRCC should require these applying plants to meet appropriate net carbon dioxide limits and toxic emission limits for mercury and other air toxics.

SEED and PC commented that the TNRCC should take supplemental comments on specific performance criteria to be met under *de novo* grandfathered facility permitting. In its narrative to the present proposal, the TNRCC states that if it embraced permitting standards beyond the minimum specified in SB 7, it "is unclear what standards these air contaminants should be held to." SEED commented that it is reasonably possible for these standards to be developed, and for nitrogen and sulfur that BACT and LAER provide an appropriate departure point. SEED and PC recommended that further supplemental comments be solicited in the second phase of this proceeding to allow for a more detailed discussion. SEED and PC commented that they are in support of the provisions in proposed §116.911 and §116.913, in that they retain the TNRCC's authority in the *de novo* permitting process.

The commission does not agree that the intent of TUC, §39.264 was to require *de novo* permitting of EGFs under the TCAA. While TUC, §39.264(e) requires EGFs to apply for a permit on or before September 1, 2000, that section goes on to say that the permit shall require the EGF to achieve emission reductions or allowances as provided by §39.264. TUC, §39.264(h) provides specific direction to the commission to base allowances on 1997 heat input, and it states emission rates for each of the defined regions. The heat input formulas were designed to achieve the 50% NO_x reductions and the 25% SO_2 reductions. The commission does not believe that it is appropriate to revise those formulas to require further reductions from grandfathered EGFs under the SB 7 program. The provisions of TUC, §39.264 do not specifically prohibit the commission from relying on the permitting requirements of the TCAA; however, the commission believes that had the Legislature intended this result, it would have placed the EGF permitting requirements in TCAA, Chapter 382. In fact, early drafts of SB 766, which did amend the TCAA, contained the permitting and allowance provisions for EGFs. Even though the EGFs included in an EGFP will not undergo a BACT and impacts analysis for initial issuance, future modifications to the EGFs themselves will be required to be processed under Subchapter B of Chapter 116. The permitting and EBTA programs will achieve a certain amount of reductions based on the provisions of TUC, §39.264. The provision in TUC, §39.264(s) recognizes that the commission has the existing authority to require additional reductions from EGFs. The commission does not believe that this section was intended to support further reductions from EGFs under the SB 7 program. Rather, it appears that the section was worded to recognize the fact that under existing law, the commission may require additional reductions from EGFs through other commission rules, such as the reasonably available control technology rules.

Even though EGFPs will not be issued using the procedures in the TCAA, these permits will not authorize noncompliance with any applicable state or federal standards, including NSPS, NESHAPS, MACTs, and federal NSR permitting requirements. The commission does not believe that it is appropriate to require grandfathered EGFs to meet the NSPS for new coal or gas plants, or to meet BACT or LAER, depending on location. As previously noted, TUC, §39.264 provided specific emission rates and goals that are to be used to implement the program. If a grandfathered EGF has made a major modification under the PSD or nonattainment NSR programs, then the facility must comply with those programs. This is a separate requirement from SB 7 and is not negated by the issuance of an EGFP.

Section 116.910(e) provides that emissions of air contaminants other than NO_x, and if applicable PM and SO_2 may be permitted by an EGFP if the grandfathered EGFs meet the requirements of Chapter 116, Subchapter H, concerning VERPs. Section 116.910(f) provides that other grandfathered facilities at a site may be permitted in an EGFP if these facilities meet the requirements to obtain a VERP. SB 7 does not require the permitting of any air contaminants other than NO_x, and if applicable PM and SO_2. Therefore, the commission chose to rely on the VERP program created by SB 766 to provide a basis of review for other air contaminants from grandfathered EGFs or grandfathered facilities so that all facilities at a site may be permitted. SB 766 provides specific control and other requirements for the permitting of grandfathered facilities. Since the Legislature passed SB 7 and SB 766 during the same session, the commission believes it is appropriate to review the grandfathered facilities and the other emissions from a grandfathered EGF using the VERP process. The commission does not believe that it is necessary to take additional comments on this issue at this time.

CSW, Entergy, Entergy Services, Reliant, CPS, Group A, and AECT commented that the permitting program as described in proposed §§116.911-116.913 is contrary to the permitting program contemplated by §39.264 of SB 7. The commenters stated that based on the language in §39.264 and the legislative history underlying it, it is clear that the SB 7 permitting program is supposed to be very different than the existing commission NSR permitting program. However, the SB 7 permitting program that proposed §§116.911-116.913 would establish is very similar to the existing commission NSR permitting program and clearly was patterned after the language in §116.111 and §116.115 of the NSR permitting program. CPS noted that in SB 7, the Legislature envisioned a program similar to EPA's Acid Rain Program.

The commenters stated that the existing NSR permitting program is a review-intensive, command and control system. Under the existing NSR permitting program rules, a permit application is subjected to a detailed and complex review that includes a BACT review, off-site impacts review, and a review to determine compliance of the proposed new or modified facility with NSPS, NESHAPs, and other state and federal air quality rules. TUC, §39.264 clearly provides that an EGF may meet its NO_x and/or SO_2 allowance(s) without adding or implementing any emissions control whatsoever. Instead, §39.264 provides that an EGF may meet its NO_x and/or SO_2 allowance(s) through emissions trading, in lieu of adding or implementing emissions controls. Moreover, nothing in §39.264 specifies, or even indicates, that if the owner/operator chooses to add or implement emissions control to cause the EGF to meet its NO_x and/or SO_2 allowance(s), that any commission review of such emissions control is to be conducted or that the commission must approve of such control. The commenters further stated that TUC, §39.204 establishes a permitting program that gives owners/operators of EFGs great flexibility in their use of NO_x and/or SO_2 allowances in exchange for severe penalties if they do not comply with their allowable allocation. AE believes that the permit program envisioned under §39.264 should be designed to be very simple and straightforward. AE believes that the application should be very short if the applicant chooses to use the FCAA required continuous emission monitoring systems (CEMS) and will use allocations derived from the Acid Rain Database.

Based on the foregoing reasons, the commenters believe that §§116.911-116.913 should be significantly simplified so that the SB 7 permitting program is less like the review-intensive, command control approach of the existing NSR permitting program, and more like the flexible permitting program that is described by the language of §39.264 of SB 7 and was contemplated by the Texas Legislature when it drafted and passed SB 7.

The commission agrees with the commenters that the permitting program required under TUC, §39.264 is narrowly constructed to permit grandfathered EGFs and to achieve a target reduction of NO_x and, if applicable, SO_2. The commission has made significant revisions to the sections in Chapter 116, Subchapter I that have simplified the application content sections and in general, the requirements of the permit program. For example, the requirements to demonstrate compliance with federal standards have been deleted. Further, the provisions regarding control methods in §116.911(a)(2) have been rewritten to address applications that propose new control technology in order to meet the emission limitations of TUC, §39.264. Subsection (a) now refers to the standard permit for the installation of controls as the basis for the review that will be used by the commission to approve these new controls. The specific revisions and responses to comments for §§116.911-116.913 follow this response.

EPA-APD commented that §§116.911(a), 116.914(f)(2), and 116.915(b) refer to miscellaneous forms. The commenter stated that the TNRCC should address why these forms are not included in the proposed rulemaking and subject to public review and comment.

The text of the application forms are not part of the rules; however, the commission welcomes comment at any time whenever forms, instructions, and guidance documents can be improved or clarified. Section 116.915, concerning Emission Control Changes, has been deleted from the adopted rule package for reasons discussed elsewhere in this adoption preamble.

B&P commented that §116.18(2)(B) should be revised so that the EGF's maximum design heat input is measured in MMBtu per hour versus MMBtu to calculate capacity factor.

The commission agrees, and has revised the definition of "Capacity factor" in §116.18(2)(B) accordingly.

Reliant commented that §116.910(a) should be revised as follows: "The owner or operator of a grandfathered facility (as defined in 116.10 of this title (relating to general definitions)) at sites with EGFs ...." As proposed, the word "grandfathered" is not defined in this section of the regulations. The commenter suggested that the commission refer to §116.10 to avoid ambiguity.

The commission has not revised §116.910(a) in response to this comment. The commission instead chose to revise the definition of "Electric generating facility" and to include a definition of "Grandfathered EGF" to make a clear distinction that a "Grandfathered EGF" means an EGF that is not subject to the requirement to obtain a permit under TCAA, §382.0518(g). Section 116.910(a) was also revised in response to this comment.

Lloyd Gosselink commented that §116.910(a) does not apply to municipal utilities or electric cooperatives. TUC, §39.002 (Applicability) provides that Chapter 39 (except for §§39.157(e), 39.203 and 39.904) does not apply to a municipally-owned utility or an electric cooperative. Thus, TUC, §39.264 does not apply. Lloyd Gosselink recommended that §116.910(a) be revised to read: "The owner or operator of a grandfathered electric generating facility (EGF) shall apply for a permit to operate that facility under this Subchapter. This requirement does not apply to a municipally owned utility or an electric cooperative." PC commented that SB 7 requires emission reductions from grandfathered power plants owned by investors or municipalities.

The commission has made no changes in response to this comment. TUC, §39.002, addresses the applicability of Chapter 39, Restructuring of Electric Utility Industry. That section excludes "municipally owned utilities" and "electric cooperatives" from the requirements of Chapter 39, with some exceptions. TUC, §39.264 was added to SB 7 during the final days of the legislative session. Its very specific intent is to require grandfathered EGFs to obtain a permit from the commission and to obtain reductions of NO_x and SO_2 in the regions as defined by the bill.

The Code Construction Act, §311.021, Texas Government Code, provides that "In enacting a statute, it is presumed that: (1) compliance with the constitutions of this state and the United States is intended; (2) the entire statute is intended to be effective; (3) a just and reasonable result is intended; (4) a result feasible of execution is intended; and (5) public interest is favored over any private interest." Although the commenter is correct in noting that TUC, §39.002 specifically excludes municipally owned utilities, that section must be read in context with the rest of Chapter 39.

TUC, §39.264 defines an "electric generating facility" as a facility that generates electricity for compensation and is owned or operated by a person in this state, including a municipal corporation, electric cooperative, or river authority. No definition of "municipal corporation" is provided in SB 7; thus, it is appropriate to consider the definition of "municipally owned utility" for guidance on what was intended to be covered by the term "municipal corporation." The term "municipally owned utility" is defined in TUC, §11.003(11) as a "utility owned, operated, and controlled by a municipality or by a nonprofit corporation the directors of which are appointed by one or more municipalities." It is reasonable to interpret the term "municipal corporation" to be the same as the term "municipally owned utility," since the terms are both used in the context of the electric utility industry in SB 7. Since the definition of "electric generating facility" includes "municipal corporations," it is appropriate to conclude that the Legislature intended for municipal corporations to be specifically included in the permitting program. The Legislature specifically noted exceptions for applicability in TUC, §39.264, and in spite of the undefined term "municipal corporation," the commission believes that the specific permitting requirements of TUC, §39.264 control over the general applicability requirements of TUC, §39.002. By interpreting TUC, §39.264 in this manner, a just and reasonable result occurs, since the interpretation enables the affected sections of Chapter 39 to be effective. The exemption provided by TUC, §39.002 allows municipal utilities and electric cooperatives to be exempt from the deregulation provisions. Municipal corporations and electric cooperatives with EGFs with nameplate capacities of 25 megawatts or less are not required to participate in the EBTA or the permitting program. Those over that amount must obtain permits and participate in the EBTA. Since TUC, §39.264 does not specifically exempt municipal corporations and electric cooperatives with EGFs with nameplate capacities over 25 megawatts, the commission does not believe it is appropriate to exclude those EGFs. The commission believes that the applicability exceptions in TUC, §39.002 are intended to exempt EGFs from the competition provisions of Chapter 39, not the permitting program.

EPA-ARD commented that various paragraphs in §116.910 are not clear as to who is taking action. For example, subsection (b) presumes that it is the owner or operator, and subsection (e) presumes that it is the commission.

The commission believes that clarification of the rules is warranted. The commission believes the proposed rule was clear as to who was taking action in §116.910(b), concerning electing facilities; however, to ensure clarity, the commission has revised subsection (b) to include a reference to "owners or operators." The commission has not revised §116.910(e), since that subsection was intended to address which air contaminants can be permitted under the requirements of Subchapter H and which may be permitted using the procedures in Chapter 116, Subchapter I, concerning the VERP program.

Reliant, TXU, Brazos Electric, Entergy, Entergy Services, Group A, AECT, and CPS commented that electing EGFs should not be subject to a full permit review as part of their electing, but that instead, their allowances should be issued through a permit alteration. The commenters stated that the proposal's requirements for electing EGFs are far more complex than intended in SB 7. SB 7 only requires that electing EGFs must be allocated NO_x and SO_2 allowances and that they specify the identity of the electing EGFs. SB 7 has no other requirements for electing EGFs. The commenters stated that §116.910(a) and (b) and §116.913 should be revised to meet these goals. A similar comment was received from EPA-APD, noting that §116.912 should be clarified that all conditions in the existing permits of electing EGFs should continue to apply and are carried into the EGF permit. The TNRCC must authorize any changes or revisions to the conditions of the existing NSR permit (including PSD and nonattainment (NA) review permits) consistent with Chapter 116, Subchapter B.

The commission believes that SB 7 allows an EGF not covered by TUC, §39.264 to become subject to the requirements of TUC, §39.264, which include the requirement to obtain an EGFP. The commission agrees that the process to include electing EGFs in the Subchapter I permitting program can be simplified. Accordingly, the commission has revised §116.910(b) to allow for the electing EGF's NSR permit to be altered consistently with the requirements for alterations in §116.116(c). Electing EGFs must notify the commission of their intent to be included in the EGF permit program under Subchapter I for the purpose of obtaining allowances for NO_x and, if applicable, SO_2. The commission believes that it is necessary to alter the NSR permit to include a cross-reference to the EGFP. Electing EGFs must submit a separate application by September 1, 2000. After reviewing both the application for the EGFP and the alteration, the EGFP that goes to public notice will include only those conditions that are required under Subchapter I. The terms and conditions of the altered NSR permit will not be subject to public notice. The EGFP may include certain provisions from the NSR permit that are necessary to ensure compliance with the allowance system. Because the rule has been revised to include the permit alteration procedures, the references to "combined permits" have been deleted from §116.18(4) and §116.912(a)(3) and (4) and (b)(6). Further, to simplify the provisions for electing EGFs, many of the provisions in §116.912, concerning application content for electing EGFs, were moved to §116.911. Section 116.912(b) is now §116.912(a) and contains the provisions for opting in and out of the permitting program.

EPA-APD commented that §116.910(b) requires electing facilities to consolidate existing NSR terms into the EGFP. EPA-APD interpreted this to include all applicable terms of the existing NSR permit, including terms and conditions of PSD, nonattainment, and minor NSR permits. EPA- APD requested confirmation of this interpretation.

As discussed previously in this adopted preamble, the commission has deleted the procedures for combining NSR permits with EGFP from the adopted rule. Since the existing NSR permits will only be altered to include a reference to the EGFPs for the electing EGF, the terms and conditions of the NSR permit will continue to apply.

EPA-ARD suggested moving §116.910(c) closer to the beginning, since it is basic to the entire section.

The commission has made no changes in response to this comment. The commission believes that the organization of §116.910 is clear as to the rule's applicability.

LP&L requested that the commission add the following sentence to §116.910(d): "If the municipal cooperation, electric cooperative, or river authority reevaluates its intent to exclude the Electric Grandfathered Facilities (EGFs) it notified the commission of prior to January 1, 2000, it may choose to elect to permit any of those EGFs at a later date." LP&L believes that this statement, if added, would bring more exempted EGFs into the emissions trading and allowance program after they have had a chance to fully evaluate the compliance costs associated with the EGF permit.

The commission believes that a municipal corporation, electric cooperative, or river authority with grandfathered EGFs with a nameplate capacity of 25 megawatts or less or electing EGFs owned by these entities can decide to participate in the permitting program under Subchapter H at a date later than January 1, 2000, by using the provisions in §116.912, concerning electing EGFs. However, applications for EGFPs must be submitted by September 1, 2000. Section 116.910(d) has been revised to allow municipal corporations, electric cooperatives, or river authorities to reevaluate their decision to exclude certain EGFs and to participate in the permitting program. Further, §101.333(4)(A)(ii), now §101.333(5)(A)(ii), has been revised to provide that allowances for municipal corporations, electric cooperatives, or river authorities, that choose to participate in the permitting and EBTA program, will be issued by January 1, 2001.

B&P commented that §116.910(e) states that the permitting requirements apply to "any EGF" or "coal fired EGFs." The commenter stated that this language should be revised to provide that the permitting requirements apply only to grandfathered and electing EGFs, and that "emissions of other air contaminants from EGFs ...," should be changed to refer to only grandfathered EGFs. EPA- ARD commented that clarification is needed in §116.910(e) on whether the trading program only applies to coal-fired facilities, since only coal-fired EGFs are permitted for SO_2.

The commission agrees, and has added the term "grandfathered and electing EGFs" to §116.910(e). The rule has also been revised to clarify that emissions other than NO_x , SO_2, or PM from grandfathered EGFs may be permitted using an EGFP, provided that the conditions of Subchapter H are met concerning VERPs. The EBTA applies to grandfathered and electing EGFs that emit NO_x and, if coal- fired, SO_2.

CSW, Reliant, TXU, Lloyd Gosselink, CEED, Entergy Services, and AECT commented on §116.910(e) and §116.913(a) that the TNRCC does not have statutory authority to impose ten-year old BACT on contaminants other than NO_x and SO_2. CSW commented that the intent of SB 7 is to permit all other air contaminants at their existing (grandfathered) allowables. LP&L commented that §116.913(a)(1)(C) and all other references to EGFs meeting the requirements of Chapter 116, Subchapter H, should be deleted from the proposed regulations, and that the language as stated in SB 7 does not authorize the commission to apply emission control standards other than NO_x and SO_2. The legislation also does not authorize the commission to develop and regulate EGF permits as those permits in the VERP program. B&P commented that §116.913(a)(1)(C) provides that each EGFP will include a general condition that authorizes emissions of air contaminants other than NO_x and SO_2 from EGFs meeting the requirements of Chapter 116, Subchapter H. The commenter stated that the section should be revised, since emissions of other air contaminants from electing EGFs will not be authorized under Chapter 116, Subchapter H.

The permitting program established by SB 7, which is contained within the TUC rather than the TCAA, addresses only emissions of NO_x, SO_2, and, by including a standard for opacity, PM. Other pollutants, such as VOC and CO, were not addressed and therefore, are not required to undergo a permitting process under TUC, §39.264. The commission believes the intent of SB 7 was also to eliminate the grandfathered status of EGFs. However, SB 7 did not specify the criteria for permitting air contaminants other than those addressed by SB 7, nor does it require the permitting of other air contaminants from grandfathered EGFs. The commission believes that it is not appropriate to merely include the existing allowable emission rates for emissions other than NO_x, or, if applicable, SO_2 for grandfathered EGFs in an EGFP. This is consistent with the commission's longstanding policy to not treat certain facilities as being "permitted" simply because the facilities are consolidated into an existing permit. For example, a facility that was originally authorized by an exemption will continue to be authorized under the exemption even though the exemption is consolidated with an NSR permit during an amendment or at renewal. Since the Legislature passed SB 7 and SB 766 during the same session, the commission believes that it is appropriate to review the grandfathered facilities and the emissions of contaminants not addressed by SB 7 from a grandfathered EGF using the VERP process. SB 766 provides specific control and other requirements for the permitting of grandfathered facilities. In order to provide an option for the complete permitting of grandfathered EGFs under the TCAA, §116.910(e) provides that emissions of air contaminants other than NO_x, SO_2, and PM may be permitted by an EGFP if the grandfathered EGF meets the requirements of the VERP program. Section 116.910(e) does not require grandfathered EGFs to permit emissions other than NO_x, SO_2, or PM. The choice to permit other air contaminants from grandfathered EGFs or grandfathered non-EGFs remains with the applicant. The rule provides that if those emissions or non-EGFs are to be permitted, they will be reviewed using the VERP process. Section 116.913(a)(1)(C) has been deleted. A new §116.913(a)(2) and (3) is included in the final rule. Section 116.913(a)(2) provides that an EGFP may permit emissions of all other air contaminants from grandfathered EGFs, provided the EGFs meet the requirements of the VERP program. Section 116.913(a)(3) allows grandfathered EGFs to consolidate a VERP with an EGFP.

EPA commented that §116.910(e) states that "other contaminants may be permitted ...." EPA-APD asked if this means that a facility can remain grandfathered for VOC, PM, CO, and lead. Secondly, EPA-APD stated that it appears that §116.913(a)(1)(C) requires inclusion of these contaminants in the permit.

The permitting program established by SB 7, which is contained within the TUC rather than the TCAA, addresses only emissions of NO_x, SO_2, and, by including a standard for opacity, PM.

Other pollutants, such as VOC and CO, were not addressed and therefore, are not required to undergo a permitting process under TUC, 39.264. Because the TCAA requires that facilities rather than pollutants be permitted, the EGF itself would remain grandfathered since not all emissions from the EGF would have been through a permit review process. In order to facilitate the permitting of grandfathered EGFs under the TCAA, §116.910(e) provides that emissions of air contaminants other than NO_x, SO_2, or PM may be permitted by an EGFP if the grandfathered EGFs meet the requirements of Chapter 116, Subchapter H, relating to VERP, which provides specific control and other requirements for the permitting of grandfathered facilities. Since the Legislature passed SB 7 and SB 766 during the same session, the commission believes that using the VERP process is appropriate to review the pollutants not addressed by SB 7. The adopted rule does not require owners or operators to permit the other pollutants from grandfathered EGFs. This is an option that may be exercised by the owner or operator. As stated previously in this adopted preamble, TUC, §116.913(a)(1)(C) was deleted.

EPA-ARD commented that clarification is needed in §116.911(a) regarding the definition of "authorized representative" and asked if this is the same person as "authorized account representative."

The authorized representative referred to in §116.911(a) is any person who is authorized to sign a form PI-1-U on behalf of the applicant. This requirement is consistent with §116.111, concerning general applications for permits under Chapter 116. The "authorized account representative" is the person who is authorized to transfer or otherwise manage allowances under Chapter 101 concerning the EBTA. The rule has not been revised in response to this comment.

Reliant commented that references to other applicable requirements (i.e., nonattainment, PSD, and §112(g)) are unnecessary and should be deleted. However, if retained, Reliant recommended that the language be revised to clarify that these programs would apply only if the EGF is undergoing a modification or other action triggering applicable requirements. B&P commented that §116.911(a)(3) and (4) should simply state that the proposed Subchapter I cannot be used to authorize construction or operation of a new source or a modification of an existing source. EPA-APD commented that §116.911(a)(3), (4), and (5) require an EGF to comply with applicable requirements of nonattainment review, PSD, and reconstructed major sources. The commenter stated that these provisions apply to new and modified sources and do not appear to apply to "grandfathered sources," and that these provisions may apply to sources which elect to opt into the program. EPA- APD further commented that first, these sections must also ensure that an electing source continues to meet all applicable provisions. Secondly, the TNRCC must add "applicable requirements of the Texas State Implementation Plan including such provisions as reasonably available control technology."

Lloyd Gosselink commented that §116.913(a)(9) should be deleted, because NSPS requirements are imposed on facilities that were constructed or modified after the publication of the applicable standard. The commenter also stated that §116.913(a)(10) should be deleted, because NESHAPS requirements are imposed on facilities that were constructed or modified after the publication of the applicable standard. Lloyd Gosselink also commented that §116.913(a)(11) should be deleted, because the requirements for NESHAPS for source categories are imposed on facilities that were constructed or modified after the publication of the applicable standard.

The commission has revised the rule in response to these comments. Section 116.911(a)(3)-(5)and §116.913(a)(9)-(11) have been deleted. These paragraphs dealt with NSPS, NESHAPs, NESHAPs for source categories, nonattainment review, PSD review, and construction or reconstruction of major sources of hazardous air pollutants. The commission agrees that TUC, §39.254 does not require EGFs to address the applicability of, or compliance with, federal standards as a condition of obtaining an EGFP or for participation in the EBTA. However, even though these paragraphs have been deleted, EGFs must still comply with these federal standards, if they are applicable. If, during the review of an application for an EGFP, the commission discovers that an EGF is out of compliance with any federal standards, the commission will initiate the appropriate enforcement action.

CSW, Entergy Services, and AECT commented that §116.911(a)(1) should be deleted in that such requirements are adequately addressed in §116.914 except for cases where alternative monitoring methods are used. CSW also commented that §116.914(d) should be revised to require submission of information to support alternative monitoring requests as soon as possible, but not later than May 1, 2002.

The commission has revised §116.911(a)(1) in response to this comment to clarify that an application must contain sufficient information for the commission to evaluate the proposed monitoring. The commission does not believe that this subsection should be deleted, since information is needed to know what emissions monitoring and reporting requirement the applicant has chosen. In addition, if the applicant is submitting a plan to comply with §116.914(d) (now §116.914(b)), it is necessary for the commission to review and approve the monitoring plans. The commission believes that the initial application submitted by September 1, 2000 should include contain sufficient detail regarding alternative monitoring requests. The commission needs sufficient time to review all monitoring proposals to ensure consistency and reliability. During the application review process, the commission will work with applicants to further refine the alternative monitoring proposal as necessary. The commission has not revised §116.914(d) (now §116.914(b)) in response to this comment.

AECT and Entergy Services commented that §116.911(a)(6) should be deleted because the proposed §116.911(a)(6) does not relate to grandfathered facilities, but rather to the use of standard permits described in §116.915 for pollution control projects. The commenters stated that in many instances, use of the §116.915 standard permit will not occur by September 1, 2000, the date the SB 7 permit application is due. Therefore, it will not be possible in many cases to include in the SB 7 permit application the information requested in §116.911(a)(6). B&P commented that in §116.911(a)(6), there is a reference to §116.915(b)(2), which does not exist. Also, B&P commented that §116.911(a)(6) is not necessary because there should be no rules that require air quality impacts analysis where there is an increase in emissions. TXU also commented that §116.911(a)(6) should be deleted because that language is not supported by §39.264 of SB 7. SB 7 does not impose any type of control technology, but specifically allows flexibility to determine what controls, if any, will be used to achieve necessary reductions. For the same reason, Reliant commented that certain parts of §116.915 should be revised to be consistent with §116.617 (Standard Permit). Specifically, §116.915 deviates from §116.617 in two respects. First, the review time should be 30 days, not the proposed 45 days; second, the proposal omits the language allowing for emission increases associated with a derate resulting from the installation of control equipment. Reliant commented that the proposed §116.915(d) does not have a counterpart in §116.617, and should be deleted, or state that these federal requirements apply if the EGF is undergoing a modification or other action triggering review under these requirements.

The commission has deleted §116.915 from the adopted rules in response to these comments. The commission will withdraw this proposed section. Since Chapter 116, Subchapter F, §116.617, Standard Permits for Pollution Control Projects, already provides the procedures for installing pollution control projects, it will simplify the adopted rule to include a cross-reference in §116.911(a)(2) to specific sections in Chapter 116, Subchapter F. The commission has revised §116.911(a)(6) (now §116.911(a)(3)) to delete the reference to §116.915 and to refer to the new §116.911(a)(2), regarding controls. This paragraph is necessary, because the commission may require modeling or monitoring to ensure public health and safety when evaluating proposed controls which cause an increase in emissions.

CSW, Reliant, TXU, Entergy, Entergy Services, B&P, Group A, AECT, and CPS commented that §116.911(a)(2) should be deleted, because that language is not supported by §39.264 of SB 7. The commenters stated that SB 7 does not impose any type of control technology, but specifically allows flexibility to determine what controls if any will be used to achieve necessary reductions.

The commission agrees that the TNRCC cannot require a grandfathered or electing EGF to use any specific control technology to ensure that their actual emissions do not exceed their allotted allowances. However, the commission does believe that if controls are going to be used to meet their emission requirements, the commission must ensure that the requirements of §116.911(2) are met. The language in §116.911(a)(2) has been revised to reference §116.617, regarding the requirements for pollution control projects, which will provide the commission sufficient information on any proposed emission controls. The requirements in §116.617 are intended to allow for the addition of new controls in a streamlined manner while ensuring that any associated emission increases will not cause adverse off-property health impacts.

EPA-ARD commented that §116.911(b) would be clear if stated in the active voice, and recommended the following language: "The owner or operator of a grandfathered EGF must submit an application for a permit on or before September 1, 2000." EPA-ARD also commented that "Grandfathered EGF" is not defined.

The commission agrees that the suggested language is clearer, and has revised the rule. The revised language is now in §116.911(c). The commission has also defined the term "Grandfathered EGF" in §116.18(9).

B&P commented that §116.911(c) should be revised to provide that applications for EGFP must be submitted under the seal of a professional engineer (P.E.) only when the capital cost of the project is greater than $2 million as provided in §116.110(e). AE questioned the need for a P.E. seal (in §116.911(c)) on a streamlined application, and stated that a P.E. seal may be required if the applicant chooses an alternate means of demonstrating compliance, such as one that would require specific engineering calculations.

The commission agrees that submittal of an EGFP application under the seal of a licensed P.E. should be done only in accordance with §116.110, as was the intent of the proposed §116.911(c). The commission has reworded this concept to clarify the intent, and moved the language to §116.911(d).

B&P commented that §116.912(a) states that electing EGFs shall submit an application "to authorize" NO_x and SO_2 emissions. The commenter stated that the TNRCC needs to revise this language, since electing EGFs are already authorized under their NSR permit.

The commission agrees that electing EGFs already had authorization to emit NO_x and SO_2; however, submitting an application under Chapter 116, Subchapter I is requesting a new authorization for NO_x, and if applicable SO_2. This authorization is necessary to allow the electing facility to obtain allowances and to participate in the EBTA. The commission believes that this is consistent with the requirements of TUC, §39.264(i). Therefore, the rule has not been revised in response to this comment. The commission notes that the NSR authorization for the NO_x, and if applicable, SO_2 and PM from electing EGFs continues in effect as enforceable permit conditions. Section 116.912(c)(1) and (2) was moved to §116.911(a)(3) in order to consolidate the application requirements for grandfathered and electing EGFs.

EDF commented that §116.912(b) allows electing EGFs to opt out of the program, and that this is not allowed in SB 7, but appears to have been added to offer additional flexibility to utility companies. The commenter stated that facilities have ample time to decide whether or not to opt in, and that this provision is not necessary. EDF commented that if the TNRCC chooses to revise the provision, the commission should allow electing EGFs to opt out only before the first control period. One individual commented that once an EGF opts into the program, it should always be in.

The rule has not been revised in response to these comments. The commission agrees that TUC, §39.264 does not expressly provide for electing EGFs to opt out of the program. However, opting out is not prohibited. Since electing EGFs are voluntarily participating in the program and are already authorized by a NSR permit, emissions reductions will not be jeopardized by allowing opting out. The commission believes that it is appropriate to allow electing EGFs to notify the commission of the decision to opt out prior to the beginning of the next control period. As the implementation of the permitting and allowance program proceeds, future rules and regulations may require operational changes at electing EGFs that may not be consistent with its allowances. Further, electing EGFs may modify a facility, thereby making its participation impracticable. The commission believes that it is appropriate to give this flexibility to an owner/operator who voluntarily participates in this program. The provisions for opting out of the program are now in §116.912(a).

B&P commented that §116.912(b)(1) and (2) should be replaced with the statement that an electing EGF's decision to opt out will become effective at the beginning of the control period following notification of the TNRCC. The commenter also stated that proposed §116.912(b)(3), (4), and (6) should be revised so that each begins with the statement, "once an EGF has opted out."

The provisions in §116.912 have been reorganized in response to this comment. The commission agrees that the rule should address when the decision to opt out will become effective and has included that language.

EPA-APD commented that §116.913(a)(1)(B) should clearly define a coal-fired EGF that is subject to limitations of SO_2. The commenter stated that it is clear that the rule applies to EGFs that fire 100% coal, but that the rule should further clarify whether these requirements apply to EGFs which fire coal in combination with other fuels and EGFs which are capable of, but not presently firing coal.

The commission has not revised §116.913(a)(1)(B) in response to the comment. The commission agrees that it is appropriate to define "coal" and "coal-fired," and has revised §101.330 and §116.18 to include the following definitions: (1) "Coal" means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388-92 "Standard Classification of Coals by Rank" (as incorporated by reference in Title 40 Code of Federal Regulations, §72.13 (effective June 25, 1999)); (2) "Coal-fired" means the combustion of fuel consisting of coal (as defined in §116.18(3)) or any coal-derived fuel (except a coal-derived gaseous fuel with a sulfur content no greater than natural gas), alone or in combination with any other fuel. The definition is independent of the percentage of coal or coal-derived fuel consumed during any control period.

EPA-APD commented that it is not clear how §116.913(a)(2) differs from §116.913(a)(1), and that if the intent is to consolidate for sources other than an EGF, e.g., a non- related boiler, it may be more clear to include the distinction in the rule.

Proposed §116.913(a)(2) (now §116.913(a)(3)) provided that the owner or operator of grandfathered facilities could consolidate the EGFP with a VERP issued under Chapter 116, Subchapter H. Proposed §116.913(a)(1) set out the applicability of the EGFP and stated that it authorized NO_x from all grandfathered or electing EGFs and, where applicable, SO_2. Section 116.913(a)(1)(C) provided that emissions from EGFs besides NO_x or SO_2 could be permitted using the requirements of the VERP program. The rule has been revised to separate §116.913(a)(1)(C) and to create a new §116.913(a)(2). This clarifies that the VERP requirements are not part of the mandatory EGFP program.

Reliant commented that §116.913(a)(5) should be revised to read that an EGF should hold a quantity of allowances for emissions of NO_x and SO_2 in its compliance account by June 30 instead of May 1.

The commission agrees that allowing EGFs a period of time to reconcile their allowance accounts is appropriate, but has revised §116.913(a)(5) (now §116.913(a)(6)) to allow a 30-day reconciliation period rather than the 60-day period requested by Reliant. The commission believes that 30 days is sufficient for reconciliation. EGFs now have until June 1 after every control period to sell or purchase allowances in order to reconcile the amount of allowances in their compliance account to ensure that the number of allowances in their account are equal to, or exceed, the amount of emissions from the prior control period.

EPA-ARD commented that §116.913(a)(6) is unclear in defining who is responsible for submitting reports of NO_x and SO_2 emissions to the permits section, and that quarterly reports may be more applicable so that sources can be evaluated each quarter instead of all at one time. Reliant commented that the report of annual actual emissions required by §116.913(a)(6) shall be submitted by August 1 instead of June 1. This would allow an additional 60 days for reconciliation. The commission revised §116.913(a)(6), now §116.913(a)(7), to refer to owners or operators. The commission believes that requiring reports of trades within 30 days of the trade, and the annual report, will provide sufficient time for a determination of compliance with the EBTA and the EGFP. The commission has revised §116.913(a)(7) to refer to the report required under §101.336(b), which requires a report of the amount of emissions of each allocated air contaminant during the preceding control period. This will clarify the reporting requirements, since it might have been unclear that the report under §116.913(a)(7) is the same as the report required under §101.336(b). The commission believes that submittal of these reports as quickly as reasonably possible is critical to expedite the review and reconciliation of compliance accounts to allot allowances for the next control period. The commission believes that 60 days is a reasonable time frame for this purpose; therefore, the rule has not been revised to allow the reports to be submitted by August 1.

B&P commented on §116.913(a)(6) and suggested that the word "prior" be added before "control period."

The commission agrees that §116.913(a)(6), now §116.913(a)(7), should be revised and has added the words "from the prior" before control period. This will clarify that the reports that are due are those that reflect the actual annual emissions from the previous control period.

EPA-APD noted that §116.913(a)(7) requires coal-fired EGFs to meet opacity limitations in 30 TAC §111.111. The commenter stated that for permitted EGFs which opt-in to the program, such EGF must also meet a more stringent opacity limit as specified in a permit issued by the TNRCC under Chapter 116 or issued by EPA under 40 CFR §52.21.

The commission agrees that if an electing EGF has an opacity limitation in its existing NSR authorization, the electing EGF must comply with the most stringent limitation. Further, the electing EGF cannot remove any existing control technology unless the modification is authorized under Chapter 116, Subchapter B. The rule was not revised in response to this comment; however, because §116.913 was revised for other reasons, §116.913(a)(7) is now §116.913(a)(8).

Reliant, Entergy, Group A, and CPS commented that §116.913(a)(8) should be deleted because SB 7 does not impose any requirement to use or not use any control technologies. Brazos Electric commented that this proposed section would prevent an electing EGF from switching to more efficient control technology or methodologies. Entergy commented that SB 7 establishes severe mandatory and permissive penalties to EGFs that exceed its allowances; thus, it is unnecessary and redundant for the proposal to contain these permit-related provisions. EPA-APD noted that §116.913(a)(8) does not permit removal of existing control technology, and that the rule should clarify whether replacement of equipment or retirement of a part of the source should be exempt from this provision.

The commission agrees that SB 7 does not impose any requirements regarding the use of control technology and has deleted §116.913(a)(8). The commission believes that a limitation of the removal of control technology is already addressed by §116.930, concerning modifications. An electing EGF is free to modify its facility as long as it obtains the appropriate NSR approval. Therefore, this provision has been deleted from §116.913(a)(8).

Lloyd Gosselink commented that §116.913(b) should be deleted, because this section fails to provide notice of what conditions might be anticipated by the TNRCC.

The commission has not revised the rule in response to this comment. The commission anticipates that special conditions may be necessary, for example, to include requirements for alternative monitoring plans or for controls that an applicant may propose to meet allotted allowances. The commission does not intend to use special conditions to place restrictions on grandfathered or electing EGFs that are more restrictive that the requirements of SB 7.

EPA-ARD commented that in §116.914(a)(1), it may be beneficial to refer to "the most current version" of 40 CFR Part 75 instead of a specific published version. This would alleviate the need to revise the regulation whenever federal rules are revised.

In order to ensure that EGFs can locate the most current version of state or federal regulations, the commission believes it is appropriate to include the date that the regulation or law was promulgated or last revised.

EPA-ARD commented that monitoring requirements in §116.914(c) for EGFs not subject to 40 CFR Part 75 should be identical to the monitoring requirements for EGFs that are subject to 40 CFR Part 75 to ensure that the amount of emissions that each allowance represents will be equivalent from one EGF to another. The commenter stated that in addition, EGFs that volunteer to join the trading program should likewise be required to monitor their emissions in accordance with 40 CFR Part 75 to ensure monitoring consistency and to not allow any cost advantage due to relaxed emissions monitoring requirements.

The commission has not revised the rule in response to this comment. However, §116.914 was reorganized for clarity. The prior §116.914(c) is now §116.914(b). The commission believes that it is appropriate to continue using 40 CFR Part 75 monitoring for those EGFs already subject to the Acid Rain Program. However, the commission does not see a basis for requiring EGFs not subject to the Acid Rain Program to implement monitoring that is more costly and beyond the requirements of 40 CFR Part 60. 40 CFR Part 60 as currently used with EGFs provides a sufficient level of accuracy that does not justify requiring the implementation of a new monitoring system. The commission believes that the use of the 1.1 adjustment factor will minimize differences in reported emissions.

EPA-ARD commented on §116.914(c) that if relative accuracies greater than 10% are allowed, an adjustment factor of 1.1 should be applied for monitors as in the OTC NO_x Budget Program.

The commission agrees, and the proposed and adopted rule reflect this understanding. In addition, the commission has added the descriptive phrase "adjustment factor" in relation to the 1.1 multiplier to §116.914(b)(2). The rule has not been revised in response to this comment.

AE commented that it is not clear in §116.914(c) whether the TNRCC is referring to all CEMS that exceed 10% relative accuracy, or just CEMS that are not subject to 40 CFR 75 that are over the 10% relative accuracy. The commenter stated that the sentence should be changed to read: "For all CEMS not subject to 40 CFR 75 that exceed 10% relative accuracy, actual emissions must be determined by multiplying the CEMS data by 1.1." However, Reliant commented that monitors on facilities not subject to 40 CFR 75 should not be required to apply the 1.1 factor, because 40 CFR 60 does not require it and is widely recognized and utilized by industry and regulatory agencies.

The commission agrees, and has reorganized §116.914(c), now §116.914(b)(2), to clearly indicate that the 1.1 adjustment factor only applies to CEMs data using a monitoring system other than 40 CFR Part 75. The 1.1 adjustment factor does not apply to CEMs data obtained under 40 CFR Part 75 because 40 CFR Part 75 invalidates any data with deviation greater than 10%.

To maintain consistency between 40 CFR Part 75 which allows adjustments up to 10% relative accuracy, any alternative monitoring including 40 CFR Part 60 will be required to apply the 1.1 adjustment factor. 40 CFR Part 60 allows up to a 20% relative accuracy, while 40 CFR Part 75 allows up to 10%. The 1.1 adjustment factor compensates for the 10% discrepancy. Therefore, the rule has not been revised to remove to remove the 1.1 adjustment factor.

EPA-ARD commented that §116.914(d) should provide standards for alternative monitoring such as what is listed under 40 CFR Part 75. EPA-APD commented that any monitoring alternatives must be approved by EPA or address why EPA approval is not applicable in this case.

In the adopted rules, the commission moved §116.914(d) to a new §116.914(b)(3) for purposes of clarity. The commission believes that the majority of grandfathered and electing EGFs are already using 40 CFR Part 75 or Part 60 monitoring, and that the majority of grandfathered and electing EGFs not required to monitor under 40 CFR Part 75 will rely on 40 CFR Part 60 for monitoring. If an EGF proposes a monitoring alternative outside of 40 CFR Part 75 or Part 60, the commission will review the proposal using existing NSR guidance for approving alternate monitoring systems. The commission does not believe that it is necessary to obtain EPA approval of alternative monitoring proposals. If an EGF which is already required to use either Part 75 or Part 60 monitoring, proposes to deviate from those programs, EPA approval must be obtained. The commission does not believe that many EGFs will propose alternative monitoring. In those instances, commission staff has ample experience and guidance to approve alternative monitoring systems. Many permits issued by the commission provide for case-by-case monitoring of discrete emission points or factors. These day-to-day decisions are not individually approved by the EPA. Since the alternative monitoring will likely be similar to Part 75 or Part 60 monitoring, the commission should be able to review and approve these alternative proposals. Commission decisions concerning alternative monitoring will be subject to public notice, since each EGFP will be subject to public notice prior to initial issuance. Interested persons and the EPA may comment on all the conditions of the permit including those relating to monitoring. The alternative plan could only be implemented after agency approval.

Reliant commented that §116.914(e)(3) should be removed because §116.914(e) sets forth the minimum requirements to be contained in a monitoring report. The commenter stated that subsection (e)(3) is ambiguous in this context and should be removed.

Section 116.914(e)(3), now §116.914(c), requires other information as needed; for example, periodic calibration results and maintenance logs. This requirement for supporting information was included to make clear that information submitted to support all monitoring protocols would need to be in sufficient detail to satisfy staff as to its effectiveness.

On the subject of public notification of an intent to apply for a permit, one individual stated that the commission should require contested case hearings in addition to notice and comment hearings. Two individuals suggested that the commission require the use of all media in an affected area for permit notice, and three more individuals stated that the commission should require publication across the state. An individual stated that the commission should require the printing of public notice in the newspaper of largest circulation in the area of the proposed permit and throughout the airshed.

TUC, §39.264(r) provides that applicants for EGFPs must publish notice in accordance with TCAA, §382.056. Section 382.056 outlines the procedures required of applicants for air permits. Permits must be noticed in a newspaper of general circulation in the municipality in which the facility is located or in the nearest municipality. If applicable, bilingual newspaper notice is required. In all cases, the applicant must post signs at the facility and the permit application must be available for review in a public place. In addition, HB 801, 76th Legislature, revised the public notice requirements for commission permits and provided additional opportunities for input, e.g., earlier notice to encourage public participation. In addition to the previous notice requirements, notices of intent to obtain a permit must include information about the opportunity to be included on mailing lists to receive updated on specific applications and the opportunity for public meetings. Because the commission believes that the notice requirements will provide ample information to ensure effective public participation, the rules have not been revised.

The commission is required to provide an opportunity for a public hearing and the submission of comment and send notice of a decision on an application in the same manner as provided by TCAA, §382.0561 and §382.0562. These sections set out the requirements for public participation for FOPs. Hearings for FOPs are not required to be conducted under the APA. Since EGFPs are to be issued using the same process as that for FOPs, hearings for EGFPs are also not required to be held under the contested case provisions of the APA. The commission does not believe it is necessary to hold two different types of hearings for EGFPs. If any facility authorized by an EGFP is modified, as that term is defined for state or federal purposes, the facility is required to obtain appropriate authorization under Chapter 116, Subchapter B. That modification would be subject to public notice and an opportunity to request a contested case hearing. The rules have not been changed in response to the comment.

One individual commented that the rules do not allow sufficient time for public comment on individual permits. The individual objected having to raise all issues by the end of the public comment period, and opposed the commission's not allowing incorporation by reference of hearing material, since this causes increased copying costs for citizens, discourages public participation, and wastes natural resources. The individual objected to the terms "reasonable" and "unreasonable" that the commission proposed in the evaluation of hearing requests.

The adopted rules allow 30 days for the submission of public comment and, if a hearing is requested and held, the comment period automatically extends to the end of the hearing. A 30-day comment period is used for all air permits, except renewals and concrete batch plants, that are subject to public notice and, in the experience of the commission, that time period has proved to be sufficient for interested persons to submit comments on permits. Further, TUC, §39.264 directs the commission to provide notice consistent with the requirements of the TCAA which requires a 30-day public comment period. In order for the commission to respond to comments in a timely manner, it is important for all comments to be submitted within a specified time period. This ensures that all comments are considered at the same time. The rules do not prohibit incorporation by reference of existing documents. Rather, they provide criteria that ensures that the documents supporting comments on permits are easily obtained and verifiable, since these documents will be included in the public record concerning an EGFP application.

Since TUC, §39.264 requires that public notice and opportunity for a hearing be done in the same manner as for FOPs, the commission is not required to hold a hearing if the basis of a request by a person who may be affected is determined to be unreasonable. Thus, reasonableness is the standard by which the commission must evaluate a hearing request on an EGFP. The commission believes that "reasonable" is a term that is circumstantial, but with a common understanding. The reasonableness of each request must be considered in light of the particular permit, the application, and the arguments raised by the protestant. For example, a hearing request based on water concerns would not be a reasonable basis for a hearing on an EGFP. Similarly, emissions from non-EGFs at a site would not be relevant to the issuance of an EGFP. Because reasonableness is very case-specific, the commission does not believe that it is appropriate to revise the rule in response to this comment.

AE commented that the term "APA" is not defined in §116.920(c).

The rule has not been revised in response to this comment. Section 3.2 of 30 TAC Chapter 3, Definitions, defines the Texas Administrative Procedure Act, Texas Government Code, Chapter 2001 and abbreviates this term as "APA." Section 3.1, Applicability, provides that words and terms, when listed in Chapter 3 and used in commission rules, shall have the meanings in that chapter, unless the context clearly indicates otherwise. However, a definition in Chapter 3 shall not apply to another chapter of the commission rules if the word or term is defined in that chapter. Since Chapter 116 does not define "APA" differently from the definition in Chapter 3, the term does not need further definition.

NFN commented on §116.920, that the publication of notice of permit hearing should not only be published in the local area, but also in the largest nearby metropolitan areas that might be affected. LWV-TX commented that the rules should require public notice in all news media in all affected areas, not just in the local newspaper. This will give citizens every opportunity for meaningful input into the permitting process. PC urged the commission to require real notice of public hearings to press in all affected areas, not just in the nearest municipality. The commenter stated that the rules only require that the local newspaper be notified, but surely this type of information could be given by the TNRCC to newspapers in communities affected by transportation and also made available on the website. One individual commented that the rules should require more public notice beyond a small ad in a newspaper and urged the use of community newspapers in addition to large newspapers in large cities. PC commented that public notice should be given in the municipality adjacent to a plant due to the fact that there are people who are affected who live upwind or downwind and are affected by transport of emissions from power plants.

The rule has not been revised in response to these comments. TUC, §39.264(r) requires applicants for EGFPs to publish notice of intent to obtain a permit in accordance with TCAA, §382.056, which outlines the procedures required of applicants for air permits. Permits must be noticed in a newspaper of general circulation in the municipality in which the facility is located or the nearest municipality. If applicable, bilingual notice is required. In all cases, applicants must post signs at the facility. HB 801 revised the public notice requirements for commission permits. In addition to the previous notice requirements, notices of intent to obtain a permit must include information about the opportunity to be included on mailing lists to receive updates on specific applications and the opportunity for public hearings. The commission is required to provide an opportunity for public hearing and for the submission of public comment and to send notice of a decision on the application in the same manner as provided by TCAA, §382.0561 and §382.0562, which are the hearing and notice requirements for FOPs. The commission believes that these procedures adequately notify persons who may be affected by emissions from EGFs. The adopted rule requires that notice be provided in the nearest municipality if no newspaper of general circulation is available in the municipality where the EGF is located. Since the commission is proposing additional SIP rules intended to address the issue of transport, the opportunity to comment on transport issues will occur during the public comment period on those rules instead of during the consideration of individual EGFPs. The rule has not been revised in response to this comment.

Reliant commented that §116.921(a) should be revised to require public notice only for grandfathered EGFs and not for electing EGFs, since they have already undergone public review for their existing permit.

The commission revised the provisions in Subchapter I, concerning the inclusion of NSR permits for electing EGFs in an EGFP. Because the NSR permit will now only be altered to include a reference to the EGFP, the provision in §116.920(c), concerning public notice, is no longer necessary. Only the EGFP will be subject to public notice and if necessary, it will include provisions from the NSR permit. The NSR permit itself will not be subject to public notice.

EPA-APD noted that under §116.921(a), the notice and comment hearing requirements only apply to the initial issuance of an EGFP. The commenter stated that the TNRCC should address why it is not requiring notice and comment hearing for subsequent revisions to the EGFP.

The rule has not been revised in response to this comment. Section 116.930 provides that modifications to EGFs must comply with Chapter 116, Subchapter B. Therefore, any modification to an EGF would have to be done under existing NSR permitting procedures. The NSR procedures utilize contested case hearings and not notice and comment hearings. Since §116.921 is specifically for initial issuance and §116.930 is for modifications to EGFs, the commission does not believe it is necessary to revise §116.921(a).

EPA-APD commented that §116.921(b) should define what is a "reasonable" or "unreasonable" request for hearing, and that if these terms are defined elsewhere in the regulations or in the statute, a cross-reference to the applicable definition or provision of the regulation or statute would be helpful.

TUC, §39.264(r) requires applicants for EGFPs to publish notice of intent to obtain a permit in accordance with TCAA, §382.056. The commission is required to provide an opportunity for public hearing, for the submission of public comment, and to send notice of a decision on the application in the same manner as provided by TCAA, §382.0561 and §382.0562, which are the hearing and notice requirements for FOPs. TCAA, §382.0561 provides that the commission is not required to hold a hearing if the basis of the request by a person who may be affected is determined to be unreasonable. Therefore, reasonableness is the standard by which the commission must evaluate the basis of a hearing request. The commission believes that "reasonable" is a term that is circumstantial, and that the reasonableness of each request must be considered in light of the particular permit, the application, and the arguments raised by the protestant. For example, a hearing request based on water concerns would not be a reasonable basis for a hearing on an EGFP. Similarly, emissions from non-EGFs at a site would not be relevant to the issuance of an EGFP. Because reasonableness is very case-specific, the commission does not believe that it is appropriate to revise the rule in response to this comment.

AE commented that §116.921(e) states that a written transcript or tape recording must be made available to the public without stating which entity is responsible for providing this.

Because the hearings for EGFPs are notice and comment hearings, the commission does not anticipate using court reporters to create transcripts for the hearings. Commission staff will oversee each hearing and will create an audio recording of the proceedings. Copies of this tape can be obtained from the commission upon request. The commission will charge a reasonable fee to cover the cost of coping, the cost of the tape, and the transcription of the tape.

Reliant commented that §116.930 should be deleted or should clarify that other permitting options are available.

Section 116.930 provides that modifications to EGFs must comply with Chapter 116, Subchapter B. Subchapter B allows modifications under other chapters or subchapters, as appropriate. Therefore, any modification to an EGF would have to be done under NSR permitting procedures. The commission believes that this section is necessary to ensure that permit holders are aware of the process to modify EGFs and has not deleted the section in the adopted rule.

Subchapter A. DEFINITIONS

30 TAC §116.18

STATUTORY AUTHORITY

The new sections are adopted under TUC, §39.264, which authorizes the commission to develop rules for the permitting of electric generating facilities; and Texas Health and Safety Code, TCAA, §382.011, which authorizes the commission to administer the requirements of the TCAA; §382.012, which provides the commission the authority to develop a comprehensive plan for the state's air; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; §382.051, which authorizes the commission to issue permits; §382.0513, which authorizes the commission to establish and enforce permit conditions consistent with the TCAA; §382.0515, which requires applicants to provide information that assures compliance with state and federal laws and regulations; §382.0518, which authorizes the commission to issue permits for new construction and modifications; §382.0519, which authorizes the commission to issue voluntary emission reduction permits, §382.05191, which authorizes public notice for voluntary emission reduction permits; §382.05193, which authorizes permits through emissions reductions, §382.055, which authorizes the commission to establish procedures for review or renewal of a permit; §382.056, which authorizes the commission to require public notice of certain permit applications and procedures for requesting hearings and responding to comments; §382.0561, which authorizes hearing procedures for FOPs; §382.0562, which requires notices of decision; and §382.061, which authorizes the commission to delegate permitting authority to the executive director; and Texas Water Code, §5.122, which authorizes the commission to delegate uncontested matters to the executive director.

§116.18. Electric Generating Facility Permits Definitions.

The following words and terms, when used in Subchapter I of this chapter (relating to Electric Generating Facility Permits) shall have the following meanings, unless the context clearly indicates otherwise.

(1) Allowance - As defined in §101.330(1) of this title (relating to Definitions).

(2) Capacity factor - Either:

(A) the ratio of an electric generating facility's (EGF) actual annual electric output (expressed in megawatt-hours) to the EGF's nameplate capacity times 8,760 hours; or

(B) the ratio of an EGF's annual heat input (in millions of British thermal units (MMBtu)) to the EGF's maximum design heat input (in MMBtu per hour) times 8,760 hours.

(3) Coal - As defined in §101.330(6) of this title.

(4) Coal-fired - As defined in §101.330(7) of this title.

(5) Compliance account - As defined in §101.330(8) of this title.

(6) Control period - As defined in §101.330(9) of this title.

(7) Electing EGF - As defined in §101.330(11) of this title.

(8) Electric generating facility (EGF) - As defined in §101.330(12) of this title.

(9) Grandfathered EGF - As defined in §101.330(14) of this title.

(10) Nameplate capacity - The maximum electrical output (expressed in megawatts) that an EGF can sustain over a specified period of time when not restricted by seasonal or other deratings.

(11) Peaking unit - An EGF that has:

(A) an average capacity factor of no more than 10% during the past three calendar years; and

(B) a capacity factor of no more than 20% in each of those calendar years.

(12) Person - As defined in §101.330(17) of this title.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9909015
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 11, 2000
Proposal publication date: September 10, 1999
For further information, please call: (512) 239-1966

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Subchapter I. ELECTRIC GENERATING FACILITY PERMITS

30 TAC §§116.910 - 116.914, 116.916, 116.920 - 116.922, 116.930, 116.931

STATUTORY AUTHORITY

The new sections are adopted under Texas Utilities Code, §39.264, which authorizes the commission to develop rules for the permitting of electric generating facilities; and Texas Health and Safety Code, Texas Clean Air Act (TCAA), §382.012, which provides the commission the authority to develop a comprehensive plan for the state's air; §382.017, which authorizes the commission to adopt rules consistent with the policy and purposes of the TCAA; §382.0513, which authorizes the commission to establish and enforce permit conditions consistent with the TCAA; §382.051, which authorizes the commission to issue permits; §382.0518, which authorizes the commission to issue permits for new construction and modifications; §382.0519, which authorizes the commission to issue voluntary emission reduction permits, §382.05191, which authorizes public notice for voluntary emission reduction permits; §382.05193, which authorizes permits through emissions reductions, §382.055, which authorizes the commission to establish procedures for review or renewal of a permit; §382.056, which authorizes the commission to require public notice of certain permit applications and procedures for requesting hearings and responding to comments; §382.0561, which authorizes hearing procedures for FOPs; §382.0562, which requires notices of decision; and §382.061, which authorizes the commission to delegate permitting authority to the executive director; and Texas Water Code, §5.122, which authorizes the commission to delegate uncontested matters to the executive director.

§116.910. Applicability.

(a) The owner or operator of a grandfathered electric generating facility (EGF) shall apply for a permit to operate that facility under this subchapter.

(b) Owners or operators of electing EGFs opting to obtain allowances under Chapter 101, Subchapter H, Division 2 of this title (relating to Emissions Banking and Trading of Allowances), shall submit a request to alter any related existing New Source Review (NSR) permits at the time of application for a permit under subsection (a) of this section. Alterations must be consistent with the requirements of §116.116(c) of this title (relating to Changes to Facilities).

(c) The owner, or the operator who is authorized to act for the owner, of a grandfathered or electing EGF is responsible for complying with this subchapter.

(d) A municipal corporation, electric cooperative, or river authority may exclude any EGF with a nameplate capacity of 25 megawatts or less from this subchapter. The municipal corporation, electric cooperative, or river authority must notify the commission by January 1, 2000, of its intent to exclude those EGFs. If the municipal corporation, electric cooperative, or river authority reevaluates its intent to exclude EGFs, it may choose to permit any of those EGFs consistent with the requirements of this subchapter.

(e) Emissions of nitrogen oxides shall be permitted under this subchapter for any grandfathered or electing EGF. Emissions of sulfur dioxide and particulate matter shall be permitted under this subchapter only for grandfathered or electing coal-fired EGFs. Emissions of other air contaminants from grandfathered EGFs may be permitted under this subchapter, provided the grandfathered EGFs meet the requirements of Chapter 116, Subchapter H of this title (relating to Voluntary Emission Reduction Permits).

(f) Owners or operators of grandfathered facilities as defined in §116.10 of this title (relating to General Definitions) at sites with grandfathered or electing EGFs subject to this subchapter may consolidate any permit issued under Chapter 116, Subchapter H of this title with a permit issued under this subchapter.

(g) An EGF that generates electric energy primarily for internal use but that during 1997 sold, to a utility power distribution system, less than one-third of its potential electrical output capacity, or less than 219,000 megawatt-hours, is not subject to the requirements of this chapter.

§116.911. Electric Generating Facility Permit Application.

(a) Owners or operators of grandfathered or electing electric generating facilities (EGF) shall submit an application to authorize nitrogen oxides (NO_x) emissions and, if applicable, sulfur dioxide (SO_2) and particulate matter (PM) emissions. The application must include a completed Form PI-1-U, General Application. The Form PI-1-U must be signed by an authorized representative of the applicant. The Form PI-1-U specifies additional support information which must be provided before the application is deemed complete. In order to be granted an electric generating facility permit (EGFP), the owner or operator shall submit information to the commission which demonstrates that all of the following are met.

(1) Measurement of emissions and performance demonstration. Applicants must propose monitoring and reporting for the measurement of emissions and demonstration of performance consistent with §116.914 of this title (relating to Emissions Monitoring and Reporting Requirements).

(2) Control method. New control methods proposed in initial applications must comply with the requirements in §116.617(1), (3), (4)(A) and (B) and (5) - (9) of this title (relating to Standard Permit for Pollution Control Projects).

(3) Air dispersion modeling or ambient monitoring for pollution control projects. Computerized air dispersion modeling and/or ambient monitoring may be required by the commission's Air Permits Division where there is an increase in emissions to determine the air quality impacts from controls proposed under paragraph (2) of this subsection.

(4) Opacity limitations for coal-fired grandfathered and electing EGFs. The coal-fired grandfathered and electing EGFs must meet the opacity limitations of §111.111 of this title (relating to Requirements for Specified Sources).

(b) Application information for electing EGFs.

(1) In addition to the information required in this section, EGFP applications regarding electing EGFs shall contain the following information:

(A) documentation of the emissions from the 1997 Emissions Scorecard from the EPA Acid Rain Program, or if that information is not available, the actual emissions from that electing EGF for calendar year 1997;

(B) documentation of fuel consumption, fuel heating values, and heat input in millions of British thermal units (MMBtu) for calendar year 1997;

(C) identification of the electing EGFs to be included.

(2) Emissions of air contaminants from electing EGFs other than NO_x, and if applicable, SO_2 and PM, already authorized by Chapter 116 of this title (relating to Control of Air Pollution by Permits for New Construction or Modification), will not be authorized under this subchapter.

(c) The owner or operator of a grandfathered or electing EGF must submit an application for a permit under this subchapter on or before September 1, 2000.

(d) All applications for an EGFP shall be submitted under the seal of a Texas licensed professional engineer if required by §116.110(e) of this title (relating to Applicability).

§116.912. Electing Electric Generating Facilities.

An electing electric generating facility (EGF) may opt out of the requirements of this subchapter under the following conditions.

(1) The electing EGF must notify the commission of its intent to opt out prior to the beginning of the next control period. The decision to opt out of the requirements of this subchapter will become effective at the beginning of the control period that follows notification to the commission.

(2) The electing EGF may not opt out during a control period.

(3) Once the electing EGF has opted out, all of the following apply:

(A) all allowances for the electing EGF will be voided by the commission and may not be banked for subsequent use;

(B) no allowances will be allocated for subsequent control periods;

(C) the electing EGF may not participate in the emissions banking and trading of allowances at any future date;

(D) the owner or operator shall request an alteration to the existing New Source Review permit to remove the conditions referencing the electric generating facility permit.

§116.913. General and Special Conditions.

(a) The following general conditions shall be applicable to every electric generating facility permit (EGFP) unless otherwise specified in the permit.

(1) A permit issued under this subchapter authorizes the following:

(A) nitrogen oxides (NO_x) emissions from all grandfathered and electing electric generating facilities (EGF);

(B) sulfur dioxides (SO_2) emissions from coal-fired grandfathered and electing EGFs.

(C) particulate matter through opacity limitations as specified in §111.111 of this title (relating to Requirements for Specified Sources) for coal-fired grandfathered and electing EGFs.

(2) An EGFP may permit emissions of all other air contaminants from grandfathered EGFs, provided the requirements of Chapter 116, Subchapter H of this title (relating to Voluntary Emissions Reduction Permits) are met.

(3) Grandfathered facilities as defined in §116.10 of this title (relating to General Definitions) at sites with grandfathered or electing EGFs and permitted under Chapter 116, Subchapter H of this title may be consolidated with a permit issued under this subchapter.

(4) The grandfathered or electing EGF must comply with Chapter 101, Subchapter H, Division 2 of this title (relating to Emissions Banking and Trading of Allowances) including the requirement to maintain allowances in a compliance account. Allowances may be transferred in accordance with §101.335 of this title (relating to Allowance Banking).

(5) Mass emission monitoring and reporting shall be conducted in accordance with §116.914 of this title (relating to Emissions Monitoring and Reporting Requirements).

(6) On June 1 after every control period, a grandfathered or electing EGF subject to this subchapter shall hold a quantity of allowances for emissions of NO_x and, where applicable, SO_2, in its compliance account that is equal to or greater than the total emissions of that air contaminant emitted during the prior control period.

(7) Owners or operators shall submit a report of the amount of emissions of each allocated air contaminant, from the prior control period to the Air Permits Division consistent with the requirements of §101.336(b) of this title (relating to Emission Monitoring, Compliance Demonstration, and Reporting).

(8) Coal-fired grandfathered and electing EGFs must meet the opacity limitations of §111.111 of this title (relating to Requirements for Specified Sources).

(b) Special conditions may be included in the EGFP.

§116.914. Emissions Monitoring and Reporting Requirements.

(a) Grandfathered or electing electric generating facilities (EGF) subject to 40 Code of Federal Regulations Part 75, effective June 25, 1999 (40 CFR Part 75) shall do the following.

(1) For grandfathered or electing EGFs subject to the requirements of 40 CFR Part 75, concerning Continuous Emission Monitoring, all monitoring systems must comply with the initial performance testing and periodic calibration, accuracy testing, and quality assurance/quality control testing specified in 40 CFR Part 75.

(2) For grandfathered and electing EGFs subject to 40 CFR Part 75, a certified monitoring system under 40 CFR Part 75 shall be used to demonstrate compliance with this subchapter.

(A) If the grandfathered or electing EGF has a flow monitor certified under 40 CFR Part 75, nitrogen oxides (NO_x) emissions in pounds per hour shall be determined using a NO_x continuous emission monitoring system (CEMS) and the flow monitor.

(B) If the grandfathered or electing EGF does not have a certified flow monitor, but does have a NO_x CEMS, NO_x emissions in pounds per hour shall be determined by multiplying pounds of NO_x per million British thermal units (lbs/MMBtu) times heat input in MMBtu per hour (MMBtu/hr). The procedures in 40 CFR Part 75, Appendix F, concerning Conversion Procedures, Section 3, shall be used to convert the measured concentration of NO_x and a diluent (carbon dioxide (CO_2) or oxygen (O_2)) into an emission rate in lbs/MMBtu. The procedures in 40 CFR Part 75, Appendix F, Section 5, shall be used to determine the hourly heat input in MMBtu/hr. These two values (lbs/MMBtu and MMBtu/hr) shall be multiplied together to determine NO_x emissions in lbs/hr.

(C) The procedures in 40 CFR Part 75, Appendix E, concerning Optional NO_x Emissions Estimation Protocol for Gas-fired Peaking Units and Oil-fired Peaking Units, may be used to estimate the NO_x emission rate.

(b) Grandfathered or electing EGFs not subject to 40 CFR Part 75 shall comply with:

(1) the initial performance testing and periodic calibration, accuracy testing, and quality assurance/quality control testing specified in 40 CFR Part 75; or

(2) those same requirements in 40 CFR Part 60, concerning New Source Performance Standards (40 CFR Part 60). Actual emissions must be determined by multiplying the CEMs data by an adjustment factor of 1.1 for all grandfathered and electing EGFs not using a 40 CFR Part 75 monitoring system if the CEMs exceeds 10% relative accuracy.

(3) in lieu of the monitoring required by paragraph (1) or (2) of this subsection, the electric generating facility permit (EGFP) may authorize alternative monitoring to calculate mass emissions under this section. The applicant must submit the following for review of an alternative monitoring proposal:

(A) a description of the monitoring approach to be used;

(B) a description of the major components of the monitoring system, including the manufacturer, serial number of the component, the measurement span of the component, and documentation to demonstrate that the measurement span of each component is appropriate to measure all of the expected values;

(C) an estimate of the accuracy of the system and documentation to demonstrate how the estimate of accuracy was determined;

(D) a description of the tests that will be used for initial certification, initial quality assurance, periodic quality assurance, and relative accuracy; and

(E) additional information may be requested before approving a request for alternative monitoring. Alternative monitoring shall be incorporated into the EGFP.

(4) emissions in pounds per hour shall be determined using the NO_x CEMS and one of the following methods.

(A) The owner or operator may elect to comply with subsection (a)(2)(A) or (B) of this section.

(B) The grandfathered or electing EGF may use a flow monitor certified under 40 CFR Part 60 to determine emissions in pounds per hour.

(C) NO_x emissions in pounds per hour may be determined by multiplying the lbs/MMBtu times the heat input in

MMBtu/hr. The procedures in 40 CFR Part 60, Appendix A, Method 19 shall be used to convert the measured concentration of NO_x and a diluent (CO_2 or O_2) into emission rates in lbs/MMBtu. The procedures in 40 CFR Part 75, Section 5, Appendix F shall be used to determine the hourly heat input in MMBtu/hr. These two values (lbs/MMBtu and MMBtu/hr) shall be multiplied together to determine NO_x emissions in lbs/hr;

(5) for grandfathered and electing EGFs with a heat input of less than 100 MMBtu/hr and for peaking units emissions in pounds per hour, may be determined using the procedures in Appendix E of 40 CFR Part 75 to estimate the emission rate.

(c) The following requirements apply to all grandfathered and electing EGFs.

(1) During a period when valid data is not being recorded by monitoring devices approved for use to demonstrate compliance with this subchapter, missing or invalid data shall be replaced with representative default data in accordance with the provisions of 40 CFR Part 75, Subpart D, concerning Missing Data Substitution Procedures.

(2) Data collected from monitoring of grandfathered and electing EGFs shall be used to calculate the actual emissions over a control period. The information in this report shall be submitted by June 30 of each year and may be submitted with the report required under §101.336(b) of this title (relating to Emission Monitoring, Compliance Demonstration, and Reporting). At a minimum, the report shall contain the following information:

(A) a description of the monitoring protocol;

(B) a completed Form AR-1, Emissions Monitoring Data Form;

(C) other information as necessary to validate the actual emissions during the prior control period, including, but not limited to, periodic calibration results and maintenance logs.

§116.916. Permits for Grandfathered and Electing Electric Generating Facilities in El Paso County.

Grandfathered and electing electric generating facilities in El Paso County are not required to meet nitrogen oxides allowance requirements if the commission or EPA determines that reductions in nitrogen oxides emissions in the El Paso Region otherwise required by this subchapter would result in increased ambient ozone levels in El Paso County.

§116.920. Public Participation for Initial Issuance.

(a) An applicant for an electric generating facility permit (EGFP) shall publish notice of intent to obtain the permit in accordance with Chapter 39 of this title (relating to Public Notice).

(b) Public notice for an EGFP may be combined with the public notice for a voluntary emission reduction permit, under Chapter 116, Subchapter H of this title (relating to Voluntary Emission Reduction Permits).

(c) Any person who may be affected by emissions from a grandfathered or electing EGF may request the commission to hold a notice and comment hearing on the EGFP application. The public comment period shall end 30 days after the publication of Notice of Receipt of Application and Intent to Obtain Permit under §39.418 of this title (relating to Notice of Receipt of Application and Intent to Obtain Permit). Any hearing request must be made in writing during the 30-day public comment period.

(d) Any hearing regarding initial issuance of an EGFP shall be conducted under the procedures in §116.921 of this title (relating to Notice and Comment Hearings for Initial Issuance) and not under the APA.

(e) Responses to public comments and the notice of the commission's decision to issue or deny an EGFP shall be conducted under the procedures in §116.922 of this title (relating to Notice of Final Action).

(f) A person affected by a decision to issue or deny an EGFP may move for rehearing under the appropriate procedure in Chapter 50 of this title (relating to Action on Applications and Other Authorizations) and may seek judicial review under TCAA, §382.032 (relating to Appeal of Commission Action).

§116.921. Notice and Comment Hearings for Initial Issuance.

(a) The notice and comment hearing requirements apply only to the initial issuance of a electric generating facility permit (EGFP).

(b) The commission shall decide whether to hold a hearing. The commission is not required to hold a hearing if the basis of the request by a person who may be affected by emissions from a grandfathered or electing electric generating facility (EGF) is determined to be unreasonable. If a hearing is requested by a person who may be affected by emissions from a grandfathered or electing EGF, and that request is reasonable, the commission shall hold a hearing.

(c) At the applicant's expense, notice of a hearing on a draft EGFP must be published in the public notice section of one issue of a newspaper of general circulation in the municipality in which the grandfathered or electing EGF is located, or in the municipality nearest to the location of the grandfathered or electing EGF. The notice must be published at least 30 days before the date set for the hearing. The notice must include the following:

(1) the time, place, and nature of the hearing;

(2) a brief description of the purpose of the hearing; and

(3) the name and phone number of the commission office to be contacted to verify that a hearing will be held.

(d) Any person, including the applicant, may submit oral or written statements and data concerning the draft EGFP.

(1) Reasonable time limits may be set for oral statements, and the submission of statements in writing may be required.

(2) The period for submitting written comments is automatically extended to the close of any hearing.

(3) At the hearing, the period for submitting written comments may be extended beyond the close of the hearing.

(e) A tape recording or written transcript of the hearing must be made available to the public.

(f) Any person, including the applicant, who believes that any condition of the draft EGFP is inappropriate or that the preliminary decision to issue or deny the permit is inappropriate, shall raise all issues and submit all arguments supporting that position by the end of the public comment period.

(g) Any supporting materials for comments submitted under subsection (f) of this section must be included in full and may not be incorporated by reference, unless the materials are one of the following:

(1) already part of the administrative record in the same proceedings;

(2) state or federal statutes and regulations;

(3) EPA documents of general applicability; or

(4) other generally available reference materials.

(h) The commission shall keep a record of all comments received and issues raised in the hearing. This record is available to the public.

(i) The draft EGFP may be changed based on comments pertaining to whether the permit provides for compliance with the requirements of this subchapter.

(j) The commission shall respond to comments consistent with §116.922 of this title (relating to Notice of Final Action).

§116.922. Notice of Final Action.

(a) After the public comment period or the conclusion of any notice and comment hearing, the commission shall send notice by first-class mail of the final action on the application to any person who commented during the public comment period or at the hearing, and to the applicant.

(b) The notice must include the following:

(1) the response to any comments submitted during the public comment period;

(2) identification of any change in the conditions of the draft electric generating facility permit and the reasons for the change;

(3) a statement that any person affected by the decision of the commission may petition for rehearing under the appropriate procedure in Chapter 50 of this title (relating to Action on Applications and Other Authorizations) and may seek judicial review under TCAA, §382.032 (relating to Appeal of Commission Action).

§116.931. Renewal.

Electric generating facility permits shall be renewed in accordance with Chapter 116, Subchapter D of this title (relating to Permit Renewals).

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9909016
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Effective date: January 11, 2000
Proposal publication date: September 10, 1999
For further information, please call: (512) 239-1966

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TITLE 31. NATURAL RESOURCES AND CONSERVATION

Part 4. SCHOOL LAND BOARD

Chapter 155. LAND RESOURCES

Subchapter A. COASTAL PUBLIC LANDS

31 TAC §155.4

The School Land Board (Board) adopts an amendment to §155.4, relating to Permits without changes to the proposed text as published in the October 15, 1999, issue of the *Texas Register* (24 TexReg 8918). The text of the rule will not be republished.

The rule adds derelict and dilapidated structures to the criteria used by the Board to determine which structures to permit.

The adoption of the rule to add derelict and dilapidated structures to the criteria used by the Board to grant or deny permits is subject to the Texas Coastal Management Program (CMP), §505.11(a)(1)(H) of this title, relating to Actions and Rules Subject to the Coastal Management Program, and must be consistent with the applicable CMP goals and policies under §501.14(i) of this title, relating to Policies for Specific Activities and Coastal Natural Resource Areas. The General Land Office (Land Office) has reviewed this proposed action for consistency with the CMP goals and policies in accordance with the regulations of the Coastal Coordination Council (Council). The proposed action is consistent with the coastal public lands regulations which the Council has determined to be consistent with the CMP. Consequently, the Land Office has determined that the proposed action is consistent with the applicable CMP goals.

No comments were received regarding the adoption of the proposed amendment to this rule.

The Land Office has prepared a takings impact assessment for the adoption of this rule and has determined that adoption of this rule will not result in a taking of private property. To receive a copy of the takings impact assessment, please send a written request to Ms. Melinda Tracy, Texas Register Liaison, General Land Office, 1700 North Congress Avenue, Room 626, Austin, Texas 78701-1495, facsimile number (512) 463-6311.

This rule is adopted under Texas Natural Resources Code Chapter 33, §33.064 which authorizes the Board to adopt procedural and substantive rules necessary for the management of coastal public lands.

Texas Natural Resources Code §33.119 is affected by this rule.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 20, 1999.

TRD-9908897
Larry R. Soward
Chief Clerk
General Land Office
Effective date: January 9, 2000
Proposal publication date: October 15, 1999
For further information, please call: (512) 305-9129

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TITLE 34. PUBLIC FINANCE

Part 1. COMPTROLLER OF PUBLIC ACCOUNTS

Chapter 9. PROPERTY TAX ADMINISTRATION

Subchapter H. TAX RECORD REQUIREMENTS

34 TAC §9.3015

The Comptroller of Public Accounts adopts an amendment to §9.3015, concerning the report of decreased value forms, with changes to the proposed text as published in the October 29, 1999, issue of the *Texas Register* (24 TexReg 9589).

This rule is being amended to add sworn statement language to the model forms for renditions as required by Senate Bill 1359, 76th Legislature, 1999, effective September 1, 1999.

Comments were received from the chief appraiser of Gray County Appraisal District suggesting a clarification of wording in subsection (e)(1)-(3). The comptroller accepts that change and has changed the language in the subsections to clarify this point.

This amendment is adopted under the Tax Code, §22.24, which requires the comptroller to prescribe and approve appropriate forms for filing a rendition or report.

The amendment implements the Tax Code, §§22.03, 22.23, 22.24, and 22.27.

§9.3015. Report of Decreased Value Forms.

(a) All appraisal offices shall prepare and make available forms for the report of decreased value by any property owner.

(b) All forms for the report of decreased value by any property owner shall provide for the following information:

(1) a statement indicating that the report form is to be filed by the property owner after January 1 and not later than April 15;

(2) the year for which the report of decreased value is filed;

(3) the name of any taxing units to which the report of decreased value is filed;

(4) the identification of the property owner filing the report of decreased value (name and address);

(5) the legal description of the property involved in the filing of the report of decreased value and its location;

(6) the name and address of a person to contact for additional information;

(7) the date of the report of decreased value;

(8) the signature of the property owner, or the authorized officer or agent, filing the report of decreased value; and

(9) a statement that the report of decreased value is confidential and not open to public inspection, except for those instances set forth in the Tax Code, §22.27(b).

(c) In order to determine the appraised value of property that is the subject of a completed and timely filed report of decreased value, the report form will provide for the following necessary information:

(1) a statement indicating the nature and cause of decreased value of the property subject to the report; and

(2) a statement indicating that the property owner may state his or her opinion about the market value of the property subject to the report.

(d) All forms for the report of decreased value by any property owner shall require the property owner to state that the information contained in the form is true and correct to the best of the property owner's knowledge and belief. If the report is filed by someone other than the property owner, an employee of the property owner, or an employee of a property owner on behalf of an affiliated entity of the property owner, the report must be sworn before an officer authorized by law to administer an oath.

(e) All forms for the report of decreased value by any property owner shall make provision for the following information on the back of the form:

(1) the name of the person from the appraisal office who reviews the property to verify any change in value;

(2) the date the person from the appraisal office views the property subject to the report or, in the case of an oil and gas property, reviews the appraisal of the property; and

(3) the determination of any decrease in appraised value and its cause and nature by the person from the appraisal office who views the property to verify any change in value.

(f) Appraisal offices failing to establish a form for the report of decreased value as required in this section may be judged to be in compliance upon a showing to the board that a form for the report of decreased value substantially equivalent to that required in this section has been established.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 21, 1999.

TRD-9908930
Martin Cherry
Special Counsel
Comptroller of Public Accounts
Effective date: January 10, 2000
Proposal publication date: October 29, 1999
For further information, please call: (512) 463-3699

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34 TAC §9.3031

The Comptroller of Public Accounts adopts an amendment to §9.3031, concerning rendition forms, without changes to the proposed text as published in the October 29, 1999, issue of the *Texas Register* (24 TexReg 9589).

This rule is being amended to add sworn statement language to the model forms for renditions as required by Senate Bill 1359, 76th Legislature, 1999, effective September 1, 1999.

Comments were received from Harris County Appraisal District Chief Appraiser Jim Robinson requesting that each model rendition be referred to as a "form" rather than an "application." The comptroller has changed the language as requested.

Comments were received from Michael Saegert, legal counsel for Harris County Appraisal District, requesting numerous specific changes to the body of the comptroller's General Business Personal Property Rendition, the Business Personal Property Rendition of Taxable Property, the Report of Leased Personal Property, and the Confidential Aircraft Rendition. The requested changes are not required by new laws or by statute. The requested changes have been made on Harris County Appraisal

District renditions and the comptroller has approved these renditions as in substantial compliance with the comptroller's adopted renditions, provided certain specific items were marked "optional."

The commentor requests that the General Business Personal Property Rendition require the following information from the taxpayer: the date of appraisal; whether the taxpayer is in business and if the assets have been moved to a different location; requiring both the home and business address of the taxpayer; requiring that the taxpayer report unusual accrued depreciation for inventory, raw materials, goods in process, finished goods, and consigned goods; requiring information concerning markdowns of retail inventory; that the taxpayer separately itemize fuels and replacement parts; that taxpayers group furniture, fixtures, machinery, and equipment by year of acquisition; addition of a separate specific category for computerized equipment; that the general rendition inform taxpayers that they need not report on this rendition vehicles to which the special inventory tax applies; addition of a column for age or year or acquisition of special equipment; and separate treatment of business vehicles. The comptroller declines to make these changes, as they are outside the scope of the originally proposed changes. The comptroller's rendition forms are general forms intended to apply to appraisal districts and taxpayers throughout the state and are sufficient to determine the property's ownership, taxability, and situs. The comptroller approves different renditions for different types of property if the forms are in substantial compliance with the comptroller's general renditions. An appraisal district that believes it would benefit from additional information may request that the comptroller determine if the appraisal district's rendition is in substantial compliance with the comptroller's general rendition.

The commentor requests that the Business Personal Property Rendition of Taxable Property require that the taxpayer report each vehicle's model type and mileage. The commentor requests changes to the Report of Leased Personal Property that would require a general description of property under lease, bailment, consignment, or other arrangement. The commentor requested that changes to the Confidential Aircraft Rendition form be made, permitting the listing of more than one aircraft on the form and the addition of a section to address the allocation of value for both business and commercial aircraft. The comptroller declines to make the changes because the comptroller's rendition forms are general forms intended to apply to appraisal districts and taxpayers throughout the state and the current form's requirements are sufficient for the appraisal district to determine ownership, taxability, and situs; also, these changes are outside the scope of the originally proposed changes. The comptroller approves different renditions for different types of property if the forms are in substantial compliance with the comptroller's general rendition forms. An appraisal district that believes it would benefit from additional information may request that the comptroller determine if the appraisal district's rendition is in substantial compliance with the comptroller's general rendition.

Comments were received from Aransas County Appraisal District requesting that portions of the model renditions asking the taxpayer for an opinion of value be in bold type. The comptroller declines to make the requested change because the taxpayer's opinion of value is an optional item. Placing this optional item in bold type could cause confusion.

This amendment is adopted under the Tax Code, §22.24, which requires the comptroller to prescribe and approve appropriate forms for filing a rendition or report.

The amendment implements the Tax Code, §22.24 and §22.27.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 21, 1999.

TRD-9908931
Martin Cherry
Special Counsel
Comptroller of Public Accounts
Effective date: January 10, 2000
Proposal publication date: October 29, 1999
For further information, please call: (512) 463-3699

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Subchapter I. VALIDATION PROCEDURES

34 TAC §9.4035

The Comptroller of Public Accounts adopts amendments to §9.4035, concerning special types of personal property inventory, with changes to the proposed text as published in the October 29, 1999, issue of the *Texas Register* (24 TexReg 9590).

The amendments are adopted to make changes in model forms for a dealer's motor vehicle inventory declaration and dealer's motor vehicle inventory tax statement in response to Senate Bill 3033, 76th Legislature, 1999, which clarified the date on which a motor vehicle dealer is presumed to have commenced business. Amendments are also proposed to the model forms for a dealer's heavy equipment inventory tax statement and dealer's heavy equipment inventory declaration, in response to Senate Bill 1435, 76th Legislature, 1999, which changed the definition of "heavy equipment inventory" and the heavy equipment "sale price," and states when a sale of heavy equipment is considered to have occurred. Amendments are proposed to the model form for retail manufactured housing inventory declaration and retail manufactured housing inventory tax statement in response to House Bill 3197, 76th Legislature, 1999, which amended the definitions of certain manufactured homes and substituted the term "unit of manufactured housing" for the term "manufactured home."

Changes were made to subsection (a) of the proposed rule to correct statutory references. The reference to Tax Code, §23.12D and §23.12E was changed to Tax Code, §23.124 and §23.125, respectively. These references were also changed on the forms listed in subsection (f)(3) and (f)(4); subsection (f) of the proposed rule has been changed to reflect the revision of these two forms.

Comments were received from T-K-O Equipment Co. suggesting that the definition of "sales price" be added to the instructions on the dealer's heavy equipment inventory declaration form as it is on the dealer's heavy equipment inventory tax statement. The comptroller accepts that change and has added the definition to the instructions on the dealer's heavy equipment inventory declaration form.

The amendments are adopted under the Tax Code, §5.07, which requires the comptroller to prescribe the contents and form for the administration of the property tax system, Tax Code, §23.121(f), which requires the comptroller to promulgate a form entitled "Dealer's Motor Vehicle Inventory Declaration," Tax Code, §23.122(e), which requires the comptroller to promulgate a form entitled a "Dealer's Motor Vehicle Inventory Tax Statement," Tax Code, §23.124(f), which requires the comptroller to promulgate a form entitled "Dealer's Vessel and Outboard Motor Inventory Declaration," Tax Code, §23.1241(f), which requires the comptroller to adopt a dealer's heavy equipment inventory declaration form, Tax Code, §23.1242(e), which requires the comptroller to adopt a dealer's heavy equipment inventory tax statement form, Tax Code, §23.125(e), which requires the comptroller to promulgate a form entitled "Dealer's Vessel and Outboard Motor Inventory Tax Statement," Tax Code, §23.127(f), which requires the comptroller to adopt a form entitled "Retail Manufactured Housing Inventory Declaration," and Tax Code, §23.128(e), which requires the comptroller to adopt a form entitled "Retail Manufactured Housing Inventory Tax Statement." The amendments implement Tax Code, §§23.121(f), 23.122(e), 23.124(f), 23.1241(f), 23.1242(e), 23.125(e), 23.127(f), and 23.128(e).

§9.4035. Special Types of Personal Property Inventory.

(a) A property owner subject to Tax Code, §§23.121, 23.122, 23.124, 23.1241, 23.1242, 23.125, 23.127, and 23.128, may use comptroller Model Forms 50-244 and 50-246 to file a dealer's motor vehicle inventory tax statement and inventory declaration; Model Forms 50-259 and 50-260 to file a dealer's vessel and outboard motor inventory tax statement and inventory declaration; Model Forms 50-267 and 50-268 to file a retailer's manufactured housing inventory tax statement and inventory declaration; and Model Forms 50-265 and 50-266 to file dealer's heavy equipment inventory tax statement and inventory declaration. Except as provided by law, all information contained on these forms is confidential.

(b) A property owner subject to this section may use an inventory tax statement form that sets out the information in the same language and sequence as the model form. A property owner may use an inventory declaration form that sets out the information in the same language and sequence as the model form.

(c) In order to assist in the accurate reporting of taxable inventories and if the form is provided by the appraisal district, the inventory tax statement and the inventory declaration shall provide both the appraisal district's and the county tax office's names, addresses, and telephone numbers.

(d) A chief appraiser shall make available to a property owner Model Forms 50-244, 50-246, 50- 259, 50-260, 50-265, 50-266, 50-267, and 50-268. A chief appraiser may make available a different form for the inventory tax statement and inventory declaration that sets out the information in the same language and sequence as the model form.

(e) In special circumstances, the chief appraiser may use forms that provide additional information, delete information required by this section, or set out the required information in different language or sequence than that required by this section if the form has been previously approved by the Comptroller of Public Accounts.

(f) The Comptroller of Public Accounts amends the model forms listed in paragraphs (1)-(8) of this subsection by reference. Copies of these forms are available for inspection at the office of the Texas Register or can be obtained from the Comptroller of Public Accounts, Property Tax Division, P.O. Box 13528, Austin, Texas 78711-3528. Copies may also be requested by calling our toll-free number 1-800-252-9121. In Austin, call (512) 305-9999. From a Telecommunications Device for the Deaf (TDD), call 1-800-248-4099, toll free. In Austin, the local TDD number is (512) 463-4621.

(1) Dealer's Motor Vehicle Inventory Declaration (Form 50-244);

(2) Dealer's Motor Vehicle Inventory Tax Statement (Form 50-246);

(3) Dealer's Vessel, Trailer, and Outboard Motor Inventory Declaration (Form 50-259);

(4) Dealer's Vessel, Trailer, and Outboard Motor Inventory Tax Statement (Form 50-260);

(5) Dealer's Heavy Equipment Inventory Declaration (Form 50-265);

(6) Dealer's Heavy Equipment Inventory Tax Statement (Form 50-266);

(7) Retail Manufactured Housing Inventory Declaration (Form 50-267); and

(8) Retail Manufactured Housing Inventory Tax Statement (Form 50-268).

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 21, 1999.

TRD-9908932
Martin Cherry
Special Counsel
Comptroller of Public Accounts
Effective date: January 10, 2000
Proposal publication date: October 29, 1999
For further information, please call: (512) 463-3699

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Part 5. TEXAS COUNTY AND DISTRICT RETIREMENT SYSTEM

Chapter 107. MISCELLANEOUS RULES

34 TAC §107.8, §107.9

The Texas County and District Retirement System adopts new §107.8 concerning the electronic transfer of funds and new §107.9 concerning the electronic filing of documents without changes to the proposed text as published in the November 12, 1999, issue of the *Texas Register* (24 TexReg 9961). The rules are adopted to implement the authority granted to the retirement system by Section 49, Senate Bill 1129, 76th Legislature (1999), to establish rules and procedures for the electronic filing of documents and the electronic transfer of funds. New §107.8 sets out definitions and procedures applicable to subdivisions for the electronic payment of required contributions using the ACH Debit process. New §107.8 prohibits using the ACH Credit process and the wire transfer process for electronically transferring funds to the retirement system. New §107.9 sets out definitions and procedures for the electronic filing of administrative forms by or on behalf of a member, beneficiary, annuitant or subdivision.

These rules permit the use of modern technologies that will make interaction with the System quicker and more convenient for the membership and the subdivisions.

No comments were received regarding the adoption of these rules.

The rules are adopted under the Government Code, §845.102, which provides the board of trustees of the Texas County and District Retirement System with the authority to adopt rules necessary or desireable for efficient administration of the system, and §845.116, which provides the board with authority to adopt rules and procedures specifically relating to the electronic transfer of funds and the electronic filing of documents.

The Government Code, §845.116 is affected by these rules.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 23, 1999.

TRD-9909029
Terry Horton
Director
Texas County and District Retirement System
Effective date: January 12, 2000
Proposal publication date: November 12, 1999
For further information, please call: (512) 328-8889

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TITLE 37. PUBLIC SAFETY AND CORRECTIONS

Part 1. TEXAS DEPARTMENT OF PUBLIC SAFETY

Chapter 23. VEHICLE INSPECTION

Subchapter F. VEHICLE INSPECTION STATION OPERATION

37 TAC §23.73

The Texas Department of Public Safety adopts an amendment to §23.73, concerning vehicle inspection fees, without changes to the proposed text as published in the October 1, 1999, issue of the *Texas Register* (24 TexReg 8540) and will not be republished.

The justification for this section will be to ensure statewide application of the statutory fees.

Amendments to subsection (a) reflect the statutory provisions regarding inspection fees and provide for uniform application of fees statewide as passed by the 76th Legislature, 1999.

No comments were received regarding adoption of the amendment.

The amendment is adopted pursuant to Texas Government Code, §411.004(3), which authorizes the Public Safety Commission to adopt rules considered necessary for carrying out the department's work.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 22, 1999.

TRD-9908977
Dudley M. Thomas
Director
Texas Department of Public Safety
Effective date: January 11, 2000
Proposal publication date: October 1, 1999
For further information, please call: (512) 424-2135

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TITLE 40. SOCIAL SERVICES AND ASSISTANCE

Part 20. TEXAS WORKFORCE COMMISSION

Chapter 809. CHILD CARE AND DEVELOPMENT

Subchapter O. CHILD CARE TRAIN OUR TEACHERS (TOT) AWARD

40 TAC §§809.301-809.304, 809.311-809.314, 809.331, 809.332

The Texas Workforce Commission (Commission) adopts new §§809.301, 809.303, 809.304, 809.311-809.314, 809.331 and 809.332, concerning Train Our Teachers (TOT) awards, without changes and §809.302 with changes to the proposed text as published in the November 12, 1999, issue of the *Texas Register* (24 TexReg 9982).

The purpose of the new rules is to implement the provisions of House Bill 2609, (76th Legislature, Regular Session, 1999), relating to the TOT awards by providing guidelines and procedures for the application, distribution and administration of the awards and repayment of funds upon failure to meet the law's post-education requirements.

Comments were received from the Coastal Bend Local Workforce Development Board (LWDB), the Upper Rio Grande LWDB, and the North Central LWDB. Two of the commenters supported the rules and requested clarification of some aspects of the rules. One commenter opposed the rules.

Comment: One commenter supported the purpose and goal of the TOT program and the Commission's effort to raise the professional level of child care providers and teachers. The commenter also supported the criteria for eligibility and the allowable expenditures stipulated in the proposed rules, the proposed methodology for administering the program, and the Commission's approach to holding recipients accountable to their work obligation through a signed contract.

Response: The Commission agrees that raising the knowledge base and professional skills of child care teachers and providers is critical to the State's commitment to improve the quality of child care services. The Commission appreciates the commenter's support of the proposed eligibility criteria, allowable expenditures, method of administration, and provisions for promoting personal responsibility on the part of award recipients.

Comment: One commenter stated that tracking applicants would be a difficult task. Experience with current grant monies for other programs has shown problems in keeping applicants committed to their agreements.

Response: The Commission agrees with the commenter that tracking recipients will be a formidable task and has established reporting and tracking procedures specifically for the TOT program. The Commission supports personal responsibility and intends for the award recipients to fulfill the work obligation stipulated in their individual TOT contracts. Procedures are established to recoup funds from recipients who fail to do so.

Comment: One commenter objected to the Commission's decision to administer the program centrally from the State Office. The commenter stated the LWDBs could better administer the program because they already have in place the mechanisms to administer the funds expeditiously. The commenter cited the Workforce and Economic Competitiveness Act which gives the LWDBs responsibility for planning and oversight of workforce training programs. In order to fulfill that mission, the commenter stated that it is essential for the LWDBs to have control over local workforce services and for the TOT funds to be allocated to and administered by the LWDBs.

Response: The Commission disagrees with the commenter regarding the most expeditious way to administer the TOT program. Given the unknown cost of administering a new program and the uncertain commitment of the Legislature with regard to funding this initiative beyond the current biennium, the Commission believes it is best to administer this program centrally.

Background: The intent of the Legislature in promulgating House Bill 2609, and the Commission in implementing the new law, is to address both the quality and availability of child care by providing an incentive for retaining trained workers in the child care profession, thus allowing child care providers to retain qualified staff and reduce turnover. The awards will help defray tuition and other related costs for child care teachers and workers pursuing credentials or degrees in child development. The opportunity to obtain professional credentials or degrees is also expected to attract new workers to the child care profession.

The intent of the Legislature and the Commission is also to help raise the professional level of child care workers in a maximum number of facilities across the state. The new law and the rules help to increase the availability of qualified professional child care workers and ensure that certain child care facilities, as defined under Section 42.002 of the Texas Human Resources Code, will have continued access to the services of these qualified professional child care workers.

The Commission researched methods of implementing the new law and on September 9, 1999, received input from a number of stakeholders while developing these rules. Stakeholders included representatives of the following: the Legislature, the LWDBs, child care contractors, early childhood development programs, the national child care information clearinghouse, community colleges that award child care professional credentials, interested state agencies, child care providers and others.

Issues discussed by the stakeholders included: administration, scope, eligibility criteria, payment methods, eligible expenses, credential costs, methods of repayment and recoupment of awards. The Commission requested additional input from the LWDBs at a meeting held on September 16, 1999, and through a conference call on October 8, 1999.

With funds available for the Train Our Teachers Award for the FY 2000 - 2001 biennium limited to $2 million, the Commission has determined that the funds shall be used primarily for expenditures associated with obtaining professional child care training and credentials. The Commission further believes that because of the funding limitation, central administration will promote economies of scale in implementation of the TOT program. As a result, more funds will be available to train child care professionals, enhancing the quality of child care services as well as increasing the number of child care teachers and workers available to meet a critical demand in the labor market.

The rules are designed to implement legislation that brings to the forefront the importance of the quality of care for Texas' youngest residents and future workforce. The Commission anticipates that the TOT awards will directly benefit not only child care workers and their employers, but also the children of parents who are working or attending education or training, as well as the parents themselves.

The new rules are adopted under Texas Labor Code, §301.061, which provides the Commission with the authority to adopt, amend or repeal such rules as it deems necessary for the effective administration of the Commission's programs, and adopted under House Bill 2609 (76th Legislature, Regular Session, 1999), which amends Chapter 302 of the Texas Labor Code by adding § 302.006.

§809.302. Definitions.

In addition to the definitions contained in §809.2 of this title (relating to Definitions), the following words and terms, when used in this subchapter, shall have the following meanings unless the context clearly indicates otherwise.

(1) Applicant – A person applying for a Child Care Train Our Teachers award.

(2) Award – Child Care Train Our Teachers award funds, up to a maximum of $1,000 per award recipient, provided pursuant to Texas Labor Code § 302.006 and this chapter.

(3) Certified Child Care Professional (CCP) – A nationally recognized child care credential that is awarded by the National Child Care Association, Inc.

(4) Child care facility – licensed, registered, or accredited child care facility as defined by Section 42.002, Human Resource Code excluding those facilities listed in Section 42.041(b), Texas Human Resources Code.

(5) Child Development Associate (CDA) – A nationally recognized child care credential that is awarded by The Council for Early Childhood Professional Recognition.

(6) Director – The executive director of the Texas Workforce Commission or the executive director's designee.

(7) Level one certificate – A level one certificate in the area of child development or early childhood education from a public or private institution of higher education.

(8) Public or private institution of higher education – An entity as defined in Texas Education Code §61.003(15).

(9) Recipient – A person determined to be eligible who has been granted a Child Care Train Our Teachers award and has executed a contract with the Commission for purposes of receiving an award.

(10) Satisfactory completion – Completion of the educational activity with at least a "C" average for which a recipient received an award.

(11) Satisfactory progress – Maintenance of an average grade of at least a "C" in an educational activity by a recipient as referenced in §809.331(a) of this chapter (relating to Recipient Responsibilities.

This agency hereby certifies that the adoption has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority.

Filed with the Office of the Secretary of State on December 21, 1999.

TRD-9908929

J. Ferris Duhon

Assistant General Counsel

Texas Workforce Commission

Effective date: January 10, 2000

Proposal publication date: November 12, 1999

For further information, please call: (512) 463-8812

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Review of Agency Rules

This Section contains notices of state agency rules review as directed by the 75th Legislature, Regular Session, House Bill 1 (General Appropriations Act) Art. IX, Section 167. Included here are: (1) notices of *plan to review;* (2) notices of *intention to review,* which invite public comment to specified rules; and (3) notices of *readoption,* which summarize public comment to specified rules. The complete text of an agency's *plan to review* is available after it is filed with the Secretary of State on the Secretary of State's web site (http://www.sos.state.tx.us/texreg). The complete text of an agency's rule being reviewed and considered for *readoption* is available in the ***Texas Administrative Code*** on the web site (http://www.sos.state.tx.us/tac).

For questions about the content and subject matter of rules, please contact the state agency that is reviewing the rules. Questions about the web site and printed copies of these notices may be directed to the ***Texas Register*** office.

Proposed Rule Reviews

Texas Animal Health Commission

Title 4, Part 2

The Texas Animal Health Commission (commission), will review and consider for readoption, revision, or repeal of Chapter 43, Subchapter C concerning Tuberculosis in Cervidae, in accordance with the General Appropriations Act, Article IX, Section 167, 75th Legislature. The rules to be reviewed are found in Chapter 43, Subchapter C which is located in Title 4, Part II, of the Texas Administrative Code and contain the following sections: §43.20 Definitions; §43.21 General Requirements; §43.22 Herd Status Plans for Cervidae; and §43.23 Requirements for Entry into Texas.

The commission finds reason for the rule to continue to exist but will consider comments related to whether reasons for re-adoption of these rules continue to exist, whether amendments or changes are needed, or whether repeal of the chapter is appropriate. Any changes to the rules will be proposed by the commission after reviewing the rules and considering the comments received in response to this notice. Any proposed rule changes will then appear in the "Rules Proposed" section of the *Texas Register* and will be adopted in accordance with the requirements of the Administrative Procedure Act, Texas Government Code Annotated, Chapter 2001. The comment period will last for 30 days beginning with the publication of this notice of intention to review. Comments or questions regarding this notice of intention to review may be submitted in writing, within 30 days following the publication of this notice in the *Texas Register*, to Edith Smith, P.O. Box 12966, Austin, Texas 78711-2966. They may also be sent by facsimile to (512) 719-0721 or by e-mail to "comments@tahc.state.tx.us." Comments will be reviewed and discussed in a future commission meeting.

TRD-9909084
Gene Snelson
General Counsel
Texas Animal Health Commission
Filed: December 30, 1999

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The Texas Animal Health Commission (commission), will review and consider for readoption, revision, or repeal of Chapter 53 concerning Market Regulations, in accordance with the General Appropriations Act, Article IX, Section 167, 75th Legislature. The rules to be reviewed are found in Chapter 53 which is located in Title 4, Part II, of the Texas Administrative Code and contain the following sections: §53.1. Facilities; §53.2. Release of Animals; §53.3. Quarantine; §53.4. Market Identification; and §53.5. Market Recordkeeping.

The commission finds reason for the rule to continue to exist but will consider comments related to whether reasons for re-adoption of these rules continue to exist, whether amendments or changes are needed, or whether repeal of the chapter is appropriate. Any changes to the rules will be proposed by the commission after reviewing the rules and considering the comments received in response to this notice. Any proposed rule changes will then appear in the "Rules Proposed" section of the *Texas Register* and will be adopted in accordance with the requirements of the Administrative Procedure Act, Texas Government Code Annotated, Chapter 2001. The comment period will last for 30 days beginning with the publication of this notice of intention to review. Comments or questions regarding this notice of intention to review may be submitted in writing, within 30 days following the publication of this notice in the *Texas Register*, to Edith Smith, P.O. Box 12966, Austin, Texas 78711-2966. They may also be sent by facsimile to (512) 719-0721 or by e-mail to "comments@tahc.state.tx.us." Comments will be reviewed and discussed in a future commission meeting.

TRD-9909085
Gene Snelson
General Counsel
Texas Animal Health Commission
Filed: December 30, 1999

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The Texas Animal Health Commission (commission), will review and consider for readoption, revision, or repeal of Chapter 55 concerning Swine, in accordance with the General Appropriations Act, Article IX, Section 167, 75th Legislature. The rules to be reviewed are found in Chapter 55 which is located in Title 4, Part II, of the Texas Administrative Code and contain the following sections: §55.01. Testing Breeding Swine Prior to Sale or Change of Ownership; §55.2. Prohibition on the Use of Modified Live Virus Hog Cholera Vaccine; §55.3. Feeding of Garbage; §55.4. Livestock Markets Handling Swine; §55.5 Pseudorabies; §55.6. Entry Requirements;

§55.7. Slaughter Plant Requirements; §55.8. Dealer Recordkeeping; and §55.9. Feral Swine.

The commission finds reason for the rule to continue to exist but will consider comments related to whether reasons for re-adoption of these rules continue to exist, whether amendments or changes are needed, or whether repeal of the chapter is appropriate. Any changes to the rules will be proposed by the commission after reviewing the rules and considering the comments received in response to this notice. Any proposed changes will then appear in the "Rules Proposed" section of the *Texas Register* and will be adopted in accordance with the requirements of the Administrative Procedure Act, Texas Government Code Annotated, Chapter 2001. The comment period will last for 30 days beginning with the publication of this notice of intention to review. Comments or questions regarding this notice of intention to review may be submitted in writing, within 30 days following the publication of this notice in the *Texas Register*, to Edith Smith, P.O. Box 12966, Austin, Texas 78711-2966. They may also be sent by facsimile to (512) 719-0721 or by e-mail to "comments@tahc.state.tx.us." Comments will be reviewed and discussed in a future commission meeting.

TRD-9909086
Gene Snelson
General Counsel
Texas Animal Health Commission
Filed: December 30, 1999

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Finance Commission of Texas

Title 7, Part 1

In accordance with House Bill 1, the Appropriations Act, Article IX, Section 167 ("Section 167"), the Texas Finance Commission (the "commission") is undertaking a comprehensive review of 7 TAC, Subchapter B, §§1.301 1.305, concerning Appeal From Orders to Desist or To Refrain; Notice in Written Contracts; Annual Fee by Holders, Creditors, and Assignees; Notice and Processing Periods for Permit Applications; and Interpretations and Advisory Letters.

All comments and questions should be addressed to Leslie L. Pettijohn, Commissioner, Office of Consumer Credit Commissioner, 2601 North Lamar Boulevard, Austin, Texas 78705-4207; fax to 512/936-7610; or e-mail to leslie_pettijohn@occc.state.tx.us.

TRD-9909046
Leslie L. Pettijohn
Commissioner
Finance Commission of Texas
Filed: December 27, 1999

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Texas Department of Health

Title 25, Part 1

The Texas Department of Health (department) will review and consider for readoption, revision or repeal Title 25, Texas Administrative Code, Part I, Chapter 13. Health Planning and Resource Development, Subchapter A. Federal Laws and Regulations Governing Texas Public Health Services, §§13.1 - 13.3.

This review is in accordance with the requirements of the Texas Government Code, §2001.039, the General Appropriations Act, Article IX, §9-10.13, 76th Legislature, 1999.

An assessment will be made by the department as to whether the reasons for adopting or readopting these rules continue to exist. This assessment will be continued during the rule review process. Each rule will be reviewed to determine whether it is obsolete, whether the rule reflects current legal and policy considerations, and whether the rule reflects current procedures of the department. The review of all rules must be completed by August 31, 2003.

Comments on the review may be submitted in writing within 30 days following the publication of this notice in the *Texas Register* to Linda Wiegman, Office of General Counsel, Texas Department of Health, 1100 West 49th Street, Austin, Texas 78756. Any proposed changes to these rules as a result of the review will be published in the Proposed Rule Section of the *Texas Register* and will be open for an additional 30 day public comment period prior to final adoption or repeal by the department.

TRD-9909072
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 29, 1999

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The Texas Department of Health (department) will review and consider for readoption, revision or repeal Title 25, Texas Administrative Code, Part I, Chapter 61, Chronic Diseases, Subchapter B. Diabetic Eye Disease Detection Initiative, §§61.21 - 61.24; and Subchapter C. Breast and Cervical Cancer Control Program, §§61.31 - 61.42.

This review is in accordance with the requirements of the Texas Government Code, §2001.039, the General Appropriations Act, Article IX, §9-10.13, 76th Legislature, 1999.

An assessment will be made by the department as to whether the reasons for adopting or readopting these rules continue to exist. This assessment will be continued during the rule review process. Each rule will be reviewed to determine whether it is obsolete, whether the rule reflects current legal and policy considerations, and whether the rule reflects current procedures of the department. The review of all rules must be completed by August 31, 2003.

Comments on the review may be submitted in writing within 30 days following the publication of this notice in the *Texas Register* to Linda Wiegman, Office of General Counsel, Texas Department of Health, 1100 West 49th Street, Austin, Texas 78756. Any proposed changes to these rules as a result of the review will be published in the Proposed Rule Section of the *Texas Register* and will be open for an additional 30 day public comment period prior to final adoption or repeal by the department.

TRD-9909073
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 29, 1999

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The Texas Department of Health (department) will review and consider for readoption, revision or repeal Title 25, Texas Administrative Code, Part I, Chapter 91, Cancer, Subchapter A. Cancer Registry, §§91.1 - 91.14; and Subchapter B. Prostrate Advisory Committee, §91.21.

This review is in accordance with the requirements of the Texas Government Code, §2001.039, the General Appropriations Act, Article IX, §9-10.13, 76th Legislature, 1999.

An assessment will be made by the department as to whether the reasons for adopting or readopting these rules continue to exist. This assessment will be continued during the rule review process. Each rule will be reviewed to determine whether it is obsolete, whether the rule reflects current legal and policy considerations, and whether the rule reflects current procedures of the department. The review of all rules must be completed by August 31, 2003.

Comments on the review may be submitted in writing within 30 days following the publication of this notice in the *Texas Register* to Linda Wiegman, Office of General Counsel, Texas Department of Health, 1100 West 49th Street, Austin, Texas 78756. Any proposed changes to these rules as a result of the review will be published in the Proposed Rule Section of the *Texas Register* and will be open for an additional 30 day public comment period prior to final adoption or repeal by the department.

TRD-9909074
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 29, 1999

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The Texas Department of Health (department) will review and consider for readoption, revision or repeal Title 25, Texas Administrative Code, Part I, Chapter 109, Texas Department of Health Hospitals, Subchapter A. Hospital and Medical Staff Bylaws, §§109.1 - 109.7, and 109.15, and Subchapter B. Tuberculosis, §§109.25 - 109.31.

This review is in accordance with the requirements of the Texas Government Code, §2001.039, the General Appropriations Act, Article IX, §9-10.13, 76th Legislature, 1999.

An assessment will be made by the department as to whether the reasons for adopting or readopting these rules continue to exist. This assessment will be continued during the rule review process. Each rule will be reviewed to determine whether it is obsolete, whether the rule reflects current legal and policy considerations, and whether the rule reflects current procedures of the department. The review of all rules must be completed by August 31, 2003.

Comments on the review may be submitted in writing within 30 days following the publication of this notice in the *Texas Register* to Linda Wiegman, Office of General Counsel, Texas Department of Health, 1100 West 49th Street, Austin, Texas 78756. Any proposed changes to these rules as a result of the review will be published in the Proposed Rule Section of the *Texas Register* and will be open for an additional 30 day public comment period prior to final adoption or repeal by the department.

TRD-9909075
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 29, 1999

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The Texas Department of Health (department) will review and consider for readoption, revision or repeal Title 25, Texas Administrative Code, Part I, Chapter 134, Private Physchiatric Hospitals and Crisis Stabilization Units, Subchapter A. General Provisions, §§134.1 - 134.3; Subchapter B. Application and Issuance of a License, §§134.11 - 134.14; Subchapter C. Operational Requirements, §§134.21 - 134.23; Subchapter D. Physical Plant and Life Safety Code, §§134.51 - 134.54; Subchapter E. Enforcement, §§134.71 - 134.73; Subchapter F. Internal Investigation, §134.91; and Subchapter G. Cooperative Agreements, §134.101.

This review is in accordance with the requirements of the Texas Government Code, §2001.039, the General Appropriations Act, Article IX, §9-10.13, 76th Legislature, 1999.

An assessment will be made by the department as to whether the reasons for adopting or readopting these rules continue to exist. This assessment will be continued during the rule review process. Each rule will be reviewed to determine whether it is obsolete, whether the rule reflects current legal and policy considerations, and whether the rule reflects current procedures of the department. The review of all rules must be completed by August 31, 2003.

Comments on the review may be submitted in writing within 30 days following the publication of this notice in the *Texas Register* to Linda Wiegman, Office of General Counsel, Texas Department of Health, 1100 West 49th Street, Austin, Texas 78756. Any proposed changes to these rules as a result of the review will be published in the Proposed Rule Section of the *Texas Register* and will be open for an additional 30 day public comment period prior to final adoption or repeal by the department.

TRD-9909076
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 29, 1999

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The Texas Department of Health (department) will review and consider for readoption, revision or repeal Title 25, Texas Administrative Code, Part I, Chapter 289, Radiation Control, Subchapter C. Texas Regulations for Control of Radiation, §§289.118 - 289.119, and Subchapter F. License Regulations, §§289.251, 289.253, 289.256, and 289.258.

This review is in accordance with the requirements of the Texas Government Code, §2001.039, the General Appropriations Act, Article IX, §9-10.13, 76th Legislature, 1999.

An assessment will be made by the department as to whether the reasons for adopting or readopting these rules continue to exist. This assessment will be continued during the rule review process. Each rule will be reviewed to determine whether it is obsolete, whether the rule reflects current legal and policy considerations, and whether the rule reflects current procedures of the department. The review of all rules must be completed by August 31, 2003.

Comments on the review may be submitted in writing within 30 days following the publication of this notice in the *Texas Register* to Linda Wiegman, Office of General Counsel, Texas Department of Health, 1100 West 49th Street, Austin, Texas 78756. Any proposed changes to these rules as a result of the review will be published in the Proposed Rule Section of the *Texas Register* and will be open for an additional 30 day public comment period prior to final adoption or repeal by the department.

TRD-9909067
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 29, 1999

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Texas State Board of Pharmacy

Title 22, Part 15

The Texas State Board of Pharmacy proposed to review Chapter 291 (§§291.31-291.34), concerning Community Pharmacy (Class A), pursuant to the Appropriations Act, Section 167. In conjunction with this review, the agency is proposing amendments to Chapter 291 (§§291.31-291.34) published elsewhere in this issue of the *Texas Register*.

Comments on the proposal may be submitted to Steve Morse, R.Ph., Director of Compliance, Texas State Board of Pharmacy, 333 Guadalupe Street, Austin, Texas 78701.

TRD-9909021
Gay Dodson, R.Ph.
Executive Director/Secretary
Texas State Board of Pharmacy
Filed: December 23, 1999

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Texas Department of Public Safety

Title 37, Part 1

The Texas Department of Public Safety (DPS) files this notice of intention to review Chapter 28 - DNA Database; Chapter 29 - Practice and Procedure; Chapter 31 - Motorcycle Operator Training; Chapter 32 - Bicycle Safety and Education Program; and Chapter 33 - All-Terrain Vehicle pursuant to the Appropriations Act of 1997, House Bill 1, Article IX, Section 167.

As part of this review process, the DPS is proposing the repeal of Chapter 29 §§29.01-29.49 and §§29.101-29.157. The DPS is proposing amendments to Chapter 31 §§31.1, 31.4, 31.6, and 31.9-31.11. Amendments to Chapter 32 are §32.2. Amendments to Chapter 33 are §§ 33.1-33.5 and the repeal of §33.6. The proposed amendments and repeals may be found in the Proposed Rules section of the *Texas Register*. The DPS will accept comments on the Section 167 requirements as to whether the reason for adopting the rules continues to exist in the comments filed on the proposed amendments.

DPS is not proposing any changes to Chapter 28; Chapter 29: §29.201; Chapter 31: §§31.2, 31.3, 31.5, 31.7, and 31.8; Chapter 32: §§ 32.1, and 32.3-33.8. Comments regarding the Section 167 requirements as to whether the reason for adopting these sections of Chapters 18, 29, 31, and 32 continues to exist, may be submitted to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512)424-2890 within 20 days after publication of this notice of intention to review.

Any questions pertaining to this notice of intention to review should be directed to Mary Ann Courter, Chief of Legal Services, Texas Department of Public Safety, Box 4087, Austin, Texas 78773-0140, (512) 424-2890.

TRD-9908986
Dudley M. Thomas
Director
Texas Department of Public Safety
Filed: December 22, 1999

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Texas Workers' Compensation Commission

Title 28, Part 2

The Texas Workers' Compensation Commission files this notice of intention to review the rules contained in Chapter 124 concerning Carriers Required Notices and Mode of Payment and Chapter 143 concerning Dispute Resolution Review by the Appeals Panel. This review is pursuant to the General Appropriations Act, Article IX, §167, 75th Legislature, the General Appropriations Act, Section 9-10, 76th Legislature, and Texas Government Code §2001.039 as added by SB-178, 76th Legislature.

The agency's reason for adopting the rules contained in these chapters continues to exist and it proposes to readopt these rules.

Comments regarding the requirement as to whether the reason for adopting these rules continues to exist must be received by 5:00 p.m. on February 7, 2000, and submitted to Donna Davila, Office of General Counsel, Mailstop #4-D, Texas Workers' Compensation Commission, Southfield Building, 4000 South IH 35, Austin, Texas 78704-7491.

§124.1 Notice of Injury

§124.2 Carrier Reporting and Notification Requirements

§124.5 Mode of Payment Made by Carriers

§124.6 Notice of Refused or Disputed Claim

§124.7 Initial Payment of Temporary Income Benefits

§143.1 Definitions

§143.2 Description of the Appeal Proceeding

§143.3 Requesting the Appeals Panel to Review the Decision of the Hearing Officer

§143.4 Responding to a Request for Review by the Appeals Panel

§143.5 Decision of the Appeals Panel

TRD-9909066
Susan Cory
General Counsel
Texas Workers' Compensation Commission
Filed: December 29, 1999

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Adopted Rule Reviews

Texas Animal Health Commission

Title 4, Part 2

The Texas Animal Health Commission (commission) has completed the review of Chapter 36, concerning Exotic Livestock and Fowl, in accordance with the General Appropriations Act, Article IX, §167, 75th Legislature, 1997. The rules are located in Title 4, Part II, of the Texas Administrative Code and contain the following sections: §36.1, Definitions and §36.2, General Requirements. The notice of review was published in the August 20, 1999, issue of the *Texas Register* (24 TexReg 6377).

The commission received two letters with several comments on this chapter. The commission responds to the following comments. The first comment letter was submitted by Gladys Porter Zoo. The first comment was in regards to §36.1 in the definition for Camelidae contains the use of lamas and llama. The commission appreciates the comment and would state that Lama indicates the genus of the animal being regulated, which is being correctly utilized; however, where the definition indicates the species, the rule will be changed to reflect the correct spelling of llama. Their second comment was in regard to the definition for ratite and whether or not a "moa" is extinct and should be deleted. The commission appreciates the comment and is aware that the moa is extinct, but the reference definition that the agency utilized for this chapter contained "moa" as part of its definition of "ratites" and at that time the commission elected to keep the same definition. However, in order to avoid any future confusion, it will be deleted when the rule is proposed for change at a future commission meeting. Also, a comment identified "cassowaries" and "rheas" as being possibly added to the definition of Ratites. The definition was not intended to be all inclusive, but in order to provide greater guidance regarding the definition, these species, cassowaries and rheas, will be added as a proposed change to the rule to be considered at a future commission meeting. They commented that in §36.2(c)(3) under the species for "camelidae" it is noted that they are frequently reactors. Although these animals are more frequently found to be "responders" to the screening tests than cattle, we have not been aware of a greater frequency of animals classified as Reactors to the confirmatory comparative tuberculin tests. Also, the commission received comments from the North American Deer Farmers Association. Their first comment was in regard to §36.2. General Requirements that the current version of the TB UM&R as published in the Code of Federal Regulations on January 1, 1999, should include or reference any recommended amendments made at the USAHA TB Committee meeting. The commission appreciates the comment but would note that our current regulations are consistent with the rules published in the Federal Register, and the agency will update these rules to reflect adopted changes to the federal rules when they are published. Their other comment was for §31.2(d) which provides that the Executive Director of the TAHC may require an inspection or test for detection of a disease or parasite if it has been determined that there is a risk of disease. They recommend a statement be added at the end which states "...in which case, the livestock owners will be notified of such detection so that they may protect themselves from further importations." Their intent is that this be accomplished by contacting the appropriate livestock associations. The commission appreciates the comment and would note that the commission as part of its normal business practices notifies the herd owner, key commissioners who represent the affected industries, and key industry contacts. As this is reflected in current practice, the commission does not consider it necessary to put it into the rule.

The commission readopts these sections pursuant to the requirements of the General Appropriations Act, Article IX, §167, 75th Legislature and finds reasons for adopting these rules continue to exist.

This concludes the review of Chapter 36, Exotic Livestock and Fowl.

TRD-9909030
Gene Snelson
General Counsel
Texas Animal Health Commission
Filed: December 23, 1999

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The Texas Animal Health Commission (commission) has completed the review of Chapter 39 concerning Scabies, in accordance with the General Appropriations Act, Article IX, §167, 75th Legislature, 1997. The rules are located in Title 4, Part II, of the Texas Administrative Code and contains the following sections: §39.1, Definitions; §39.2, Psoroptic Scabies in Infested Herds; §39.3, Sarcoptic Scabies in Infested Herds; §39.4, Livestock Exposed to Psoroptic or Sarcoptic Scabies; §39.5, Quarantines and Release; §39.6, Duties of Owners or Caretakers of Livestock Infested with or Exposed to Scabies; §39.7, Livestock at Shows, Fairs, and Exhibitions; §39.8, Permitted Dips for Scabies and Mange Mite Eradication; §39.9, Chorioptic Mange and §39.10, Interstate Movement Requirements for Livestock. The notice of review was published in the August 20, 1999, issue of the *Texas Register* (24 TexReg 6377).

No comments were received on this chapter.

The commission readopts these sections pursuant to the requirements of the General Appropriations Act, Article IX, §167, 75th Legislature, and finds reasons for adopting these rules continue to exist.

This concludes the review of Chapter 39, Scabies.

TRD-9909031
Gene Snelson
General Counsel
Texas Animal Health Commission
Filed: December 23, 1999

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The Texas Animal Health Commission (commission) has completed the review of Chapter 41, concerning Fever Ticks, in accordance with the General Appropriations Act, Article IX, §167, 75th Legislature, 1997. The rules are located in Title 4, Part II, of the Texas Administrative Code and contain the following sections: §41.1, Tick Eradication and §41.2, Quarantine Line; Defining and Establishing Tick Eradication Areas. The notice of review was published in the August 20, 1999, issue of the *Texas Register* (24 TexReg 6377).

The commission received one letter with numerous comments focused on providing greater clarity to the rules. The letter, submitted by the Cattle Fever Tick Research Laboratory, stated that the regulations were well done and very thorough but made several suggestions in order to make them clearer and easier to understand. The commission responds to these as comments and appropriate changes will be proposed at a later commission meeting.

The first comment was to have all distinct titles for each section underlined. The commission appreciates the comment but under the formatting requirements of the Texas Register that would not be allowable.

The second comment was that the rule provides in several places "authorized representatives of the commission" are utilized to provide authority to carry out the objectives of the rules. It was suggested that the term be changed to "the commission or its authorized representative" and that the phrase be utilized to a greater extent in the regulations in order to convey this point. The commission appreciates the comment but feels like the current phrase covers the same intent as the recommended change as well as provides the necessary authority for the authorized representative to act under the rules.

The third comment is regarding the definition of adjacent premise which provides that an epidemiologist has the ability to exempt a premise from adjacent premise status. It also addressed whether it would be appropriate to broaden the authority to allow other authorized representatives to perform that function. The commission appreciates the comment but feels that rules require or limit the authority to an epidemiologist for a reason. An epidemiologist has very specialized training for performing this function and the commission feels that it is appropriate to limit that determination to an epidemiologist.

As a fourth comment it was suggested that the phrase "game proof fence", which is used in the definition for "adjacent premise", should have a specific definition. To date the commission has not experienced any problem with anyone understanding and properly obtaining a game proof fence. It is a term which is widely understood as designating a specific type of fence and there has not been a problem in making an assessment of an adjacent premise.

The fifth comment is that the definition for "exposed livestock" should be structured in such a manner as to specifically identify each individual factor utilized in defining exposed livestock. The commission appreciates the comment but feels like the current definition is clear as the commission has not experienced significant misreading of the rule for regulatory purposes. However, the commission will be making some changes to the current rule at a future meeting and at that time will give consideration to re-evaluating the form and structure of all the definitions.

The sixth comment follows the fourth comment with the same recommendation that it would be clearer and easier to understand if certain definitions were put in an outline form rather than a current narrative format. The commission would provide the same response as given to the fourth comment.

The seventh comment suggests that the definition for "infested livestock" would be clearer in outline form. The commission would provide the same response as given to the fourth comment.

Comment eight suggests that in the requirements for "movement of livestock" there should be a better explanation on the meaning of "wet". The commission appreciates the comment but to date the commission has not experienced any problem with anyone understanding and properly complying with the requirement. As it is necessary for a certificate of movement to be issued to the herd owner prior to movement, it affords the commission or its authorized representative the ability to ensure compliance with this requirement if an animal gets wet.

Comment nine is in regards to the same requirements for "movement of livestock" and states the commission should address the possibility in the event that cattle are exposed to rain or get in a stock tank. The commission would note that it has not experienced any problems in compliance with this requirement. The rules currently provide that if it rains and the dip is washed off prior to drying, then another dip is required. As such, the commission considers the current rules to be sufficient.

Comment ten suggests putting into outline form the definition for "restrictions on movement of livestock." The commission would provide the same response as given to the fourth comment.

The eleventh comment is that for §41.1(e), "restrictions on movement of livestock", that the last listed requirement may be repeating an earlier requirement. The commission appreciates this comment and concurs that the requirement has been repeated. The commission will delete this duplication when changes are proposed to the rules at a future commission meeting.

Comment twelve addresses the definition "restrictions on movement of livestock" and is specifically regarding "movement originating in other states." The term "disinfected" is used but it should be "disinfested." The commission appreciates this comment and concurs that "disinfested" is a more appropriate term for the rule. The commission will make this change when changes are proposed to the rules at a future commission meeting.

Comment thirteen suggests in §41.1(g) to change some awkward wording in dipping livestock with the official dip. The commission would provide the same response as given to the fourth comment.

Comment fourteen is focused on §41.1(l) and states that we should be clearer on insuring that the inspection of cattle for reloading is done in the presence of an authorized representative of the commission. The commission appreciates this comment and concurs that the requirement can be clarified so as to insure compliance. The commission will make this change when changes are proposed to the rules at a future commission meeting.

Comment fifteen in §41.2 states that the name of each county should be underlined. The commission appreciates the comment but under the formatting requirements of the Texas Register that would not be allowable.

The comments regarding the "Cattle Fever Tick Task Force" are appreciated and any comments with which the commission concurs with will be proposed in a future commission meeting along with recommended changes.

The commission readopts these sections pursuant to the requirements of §167 of the General Appropriations Act, and finds reasons for adopting these rules continue to exist.

This concludes the review of Chapter 41, Fever Ticks.

TRD-9909032
Gene Snelson
General Counsel
Texas Animal Health Commission
Filed: December 23, 1999

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The Texas Animal Health Commission (commission) has completed the review of Chapter 57, concerning Poultry, in accordance with the General Appropriations Act, Article IX, §167, 75th Legislature. The rules are located in Title 4, Part II, of the Texas Administrative Code and contains the following sections: §57.10, Definitions and §57.11, General Requirements. The notice of review was published in the August 20, 1999, issue of the *Texas Register* (24 TexReg 6377).

Only one comment was received on this chapter. The comment simply stated that they were supportive of this chapter.

The commission readopts these sections pursuant to the requirements of the General Appropriations Act, Article IX, §167, 75th Legislature, and finds reasons for adopting these rules continue to exist.

This concludes the Review of Chapter 57, Poultry.

TRD-9909033
Gene Snelson
General Counsel
Texas Animal Health Commission
Filed: December 23, 1999

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TABLES & GRAPHICS

Graphic material from the emergency, proposed, and adopted sections is published separately in this tables and graphics section. Graphic material is arranged in this section in the following order: Title Number, Part Number, Chapter Number and Section Number.

Graphic material is indicated in the text of the emergency, proposed, and adopted rules by the following tag: the word "Figure" followed by the TAC citation, rule number, and the appropriate subsection, paragraph, subparagraph, and so on. Multiple graphics in a rule are designated as "Figure 1" followed by the TAC citation, "Figure 2" followed by the TAC citation.

Figure: 4 TAC §45.2(a)

Multiple species diseases

Akabane - Akabane virus
Anthrax *, **- Bacillus anthracis
Aujeszky's disease - Pseudorabies virus, herpesvirus suis
Leishmaniasis** - Leishmania infantum and L donavani
Foot and mouth disease - Aphthovirus, types A,O,C, SAT, Asia
Heartwater - Cowdria ruminantium
African Trypanosomosis (Nagana) - Trypanosoma brucei, T. vivax, T. brucei
Rinderpest - Morbillivirus
Rift Valley fever - Bunya virus
Vesicular stomatitis - Rhabdovirus; 2 serotypes; New Jersey and Indiana
Screwworm - Cochliomyia hominivorax

Cattle diseases (including Exotic Bovidae)

Bovine babesiosis - *B. bovis, B. divergens*, Babesia microti
Bovine brucellosis - Brucella abortus
Bovine ephemeral fever - Rhabdovirus
Bovine tuberculosis - Mycobacterium bovis
East coast fever (Theileriosis) - Theileria parva
Malignant catarrhal fever (wildebeest associated) - Alcelaphine herpesvirus (AHV 1)
Contagious bovine pleuropneumonia - Mycoplasma mycoides
Lumpy skin disease - Neethling poxvirus
Bovine spongiform encephalopathy -
Scabies * - Sarcoptes scabiei, Psoroptes bovis, Chorioptes bovis

Equine diseases

African horse sickness - Orbivirus
Contagious equine metritis - Tayorella equigenitalis
Dourine - Trypanosoma equiperdum
Epizootic lymphangitis - Histoplasma farciminosum
Equine encephalomyelitis (Eastern and Western) *, ** - Alphavirus
Equine infectious anemia * - Lentivirus
Equine morbillivirus pneumonia - Morbillivirus
Equine piroplasmosis - Babesia equi, B. caballi
Glanders - Pseudomonas mallei
Japanese encephalitis - Flavovirus
Surra - Trypanosoma evansi
Venezuelan equine encephalomyelitis** - Alphavirus; Togaviridae family

Swine diseases

African swine fever - Poxvirus
Classical swine fever (hog cholera) - Togovirus
Pseudorabies - Herpesvirus suis
Porcine brucellosis - Brucella suis
Swine vesicular disease - Picornavirus
Vesicular Exanthema - Calicivirus

Poultry diseases

Avian influenza * - Orthomyxoviruse

Avian infectious laryngotracheitis - Orthomyxovirus; herpesvirus
Avian tuberculosis * - Mycobacterium avium serovars 1,2
Duck virus hepatitis * - Picornavirus
Duck virus enteritis * - Herpesvirus
Fowl typhoid - Salmonella gallinarum
Highly pathogenic avian influenza (fowl plague) – Orthomyxovirus (type H5 or H7)
Infectious encephalomyelitis * - Arbovirus
Ornithosis (psitticosis) * - Chlamydia psittaci
Pullorum disease - Salmonella pullorum
Newcastle disease (VVND) - Paramyxovirus-1 (PMV-1)
Paramyxovirus infections (other than Newcastle disease) * - PMV-2 to PMV-9

Rabbit diseases

Myxomatosis - Myxomatosis virus

Viral haemorrhagic disease of rabbits - Calciviral disease

* These diseases will only be reportable through the last day of the 77th Texas legislative session unless continued in effect by act of the legislature.

** These diseases are also reportable to the TDH.

Figure: 30 TAC §101.333(1)

$$A = \frac{ER * HI}{\mathbf{2000\ lb/allowance}}$$

Where:

A	=	Number of allowances
HI	=	Total heat input (million British thermal units (MMBtu)) as listed in the 1997 Emissions Scorecard from EPA's Acid Rain Program, or if not listed in the 1997 Emissions Scorecard, by a method approved by the executive director, consistent with the emission reduction requirements of this division.
ER	=	Emission rate, as defined in subparagraphs (A) and (B) of this paragraph;

Figure: 30 TAC §101.334(2)

$$A = \frac{HI_{1997} \text{ x } EF_{CP}}{2000 \text{ lbs / allowance}}$$

Where:

A	=	Allowances to be subtracted from the compliance account
HI_{1997}	=	Heat input from 1997
EF_{CP}	=	The emission factor for the control period in terms of lbs/MMBtu,or if an emission factor for the control period is not available, the most recently available emission factor for that EGF.

Figure: 30 TAC §101.334(3)

$$A = \frac{(HI_{CP} \times EF_{CP}) + [(HI_{1997} - HI_{CP}) * EF_{new}]}{2000 \text{ lbs / allowance}}$$

Where:

A	=	Allowances to be subtracted from the compliance account
HI_{CP}	=	Heat input for the control period.
EF_{CP}	=	The emission factor for the control period in terms of lbs/MMBtu.
HI_{1997}	=	Heat input from 1997
EF_{new}	=	The emission factor in terms of lbs/MMBtu for the EGF that replaced the thermal energy from the reduced utilization or shutdown. If the specific EGF that replaced the thermal energy is not identifiable, the emission factor shall be equal to the average emission factor for all EGFs in the state as listed in the 1997 Emissions Scorecard from EPA's Acid Rain Program.

In Addition

The ***Texas Register*** is required by statute to publish certain documents, including applications to purchase control of state banks, notices of rate ceilings, changes in interest rate and applications to install remote service units, and consultant proposal requests and awards.

To aid agencies in communicating information quickly and effectively, other information of general interest to the public is published as space allows.

Comptroller of Public Accounts

Notice of Legal Banking Holidays

Notice of Legal Banking Holidays: Texas Tax Code Annotated §111.053(b) requires that, before January 1 of each year, the Comptroller of Public Accounts publish a list of the legal holidays for banking purposes for that year. Pursuant to the Federal Reserve Bank of Dallas Notice 99-60, dated July 29, 1999, the Federal Reserve Bank of Dallas and its branches at El Paso, Houston, and San Antonio Texas, will observe the following holidays for calendar year 2000 and will not be open on the dates indicated below:

January 17, Martin Luther King, Jr., Day

February 21, Presidents Day

May 29, Memorial Day

July 4, Independence Day

September 4, Labor Day

October 9, Columbus Day

November 23, Thanksgiving Day

December 25, Christmas Day

The Federal Reserve standard holiday schedule mandates that if January 1, July 4, November 11, or December 25 falls on a Sunday, the following Monday will be observed as a holiday. If January 1, July 4, November 11, or December 25 occurs on a Saturday, the preceding Friday will not be observed as a holiday. Because January 1, 2000, falls on a Saturday, Friday, December 31, 1999, will not be observed as a holiday by this Bank. Also, because November 11, 2000, falls on a Saturday, Friday, November 10, 2000, will not be observed as a holiday.

TRD-9909080
David R. Brown
Legal Counsel
Comptroller of Public Accounts
Filed: December 29, 1999

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Office of Consumer Credit Commissioner

Notice of Rate Ceilings

The Consumer Credit Commissioner of Texas has ascertained the following rate ceilings by use of the formulas and methods described in Sections 303.003, 303.005, and 303.009, Tex. Fin. Code.

The weekly ceiling as prescribed by Sec. 303.003 and Sec. 303.009 for the period of 01/03/00 - 01/09/00 is 18% for Consumer [1]/ Agricultural/Commercial [2]/credit thru $250,000.

The weekly ceiling as prescribed by Sec. 303.003 and Sec. 303.009 for the period of 01/03/00 - 01/09/00 is 18% for Commercial over $250,000.

The monthly ceiling as prescribed by Sec. 303.0053 for the period of 01/01/00 - 01/31/00 is 18% for Consumer/Agricultural/Commercial/ credit thru $250,000.

The monthly ceiling as prescribed by Sec. 303.005 for the period of 01/01/00 - 01/31/00 is 18% for Commercial over $250,000.

[1]Credit for personal, family or household use.

[2]Credit for business, commercial, investment or other similar purpose.

[3]For variable rate commercial transactions only.

TRD-9909052
Leslie L. Pettijohn
Commissioner
Office of Consumer Credit Commissioner
Filed: December 28, 1999

♦ ♦ ♦

Texas Department of Health

Notice of Emergency Cease and Desist Order on Barry A. Martin, M.D.

Notice is hereby given that the Bureau of Radiation Control (bureau) ordered Barry A. Martin, M.D. (registrant-R22708) of Houston to cease and desist using the Universal x-ray unit (Model Number 3398-C; Serial Number C439) until all violations stated in the Notice of Violations issued by the bureau have been corrected. The bureau determined that an immediate threat to public health and safety existed due to the excessive exposure to patients and the number of health-related violations. The order will remain in effect until the registrant receives authorization from the bureau to operate the x-ray unit.

A copy of all relevant material is available for public inspection at the Bureau of Radiation Control, Texas Department of Health, Exchange Building, 8407 Wall Street, Austin, Texas, Monday-Friday, 8:00 a.m. to 5:00 p.m. (except holidays).

TRD-9909069
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 29, 1999

♦ ♦ ♦

Notice of Emergency Cease and Desist Order on Denito Chiropractic Clinic

Notice is hereby given that the Bureau of Radiation Control (bureau) ordered Denito Chiropractic Clinic (registrant-R12510) of Allen to cease and desist performing lumbo-sacral spine (AP) x-ray procedures with the Bennett x-ray unit (Model Number C325-5; Serial Number B5250) until the exposure at skin entrance meets the Texas radiation requirements. The bureau determined that continued radiation exposure to patients in excess of that required to produce a diagnostic image constitutes an immediate threat to public health and safety, and the existence of an emergency. The order will remain in effect until the bureau authorizes the registrant to perform the procedure.

A copy of all relevant material is available for public inspection at the Bureau of Radiation Control, Texas Department of Health, Exchange Building, 8407 Wall Street, Austin, Texas, Monday-Friday, 8:00 a.m. to 5:00 p.m. (except holidays).

TRD-9909070
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 29, 1999

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Notice of Intent to Revoke the Radioactive Material License of Tru-Tag Systems, Inc.

Pursuant to 25 Texas Administrative Code §289.205, the Bureau of Radiation Control (bureau), Texas Department of Health (department), filed a complaint against the following licensee: Tru-Tag Systems, Inc., Spring, L03783.

The complaint alleges that the licensee has failed to pay the required annual fee. The department intends to revoke the radioactive material license; order the licensee to cease and desist use of such radioactive material; order the licensee to divest himself of the radioactive material; and order the licensee to present evidence satisfactory to the bureau that he has complied with the orders and the provisions of the Texas Health and Safety Code, Chapter 401. If the fee is paid within 30 days of the date of the complaint, the department will not issue an order.

This notice affords the opportunity to the licensee for a hearing to show cause why the radioactive material license should not be revoked. A written request for a hearing must be received by the bureau within 30 days from the date of service of the complaint to be valid. Such written request must be filed with Richard A. Ratliff, P.E., Chief, Bureau of Radiation Control (Director, Radiation Control Program), 1100 West 49th Street, Austin, Texas 78756-3189. Should no request for a public hearing be timely filed or if the fee is not paid, the radioactive material license will be revoked at the end of the 30-day period of notice.

A copy of all relevant material is available for public inspection at the Bureau of Radiation Control, Texas Department of Health, Exchange Building, 8407 Wall Street, Austin, Texas, Monday-Friday, 8:00 a.m. to 5:00 p.m. (except holidays).

TRD-9909054
Susan K. Steeg
General Counsel
Texas Department of Health
Filed: December 28, 1999

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Texas Health and Human Services Commission

Cancellation of Joint Public Hearing

The Texas Health and Human Services Commission and the Texas Department of Human Services (TDHS) are cancelling the joint public hearing which was to be held on January 10, 2000, to receive public comment on proposed payment rates for the following programs operated by TDHS: nursing facilities, swing beds, hospice-nursing facilities and Bienvivir Waiver. Notice of the hearing appeared in the December 24, 1999, issue of the *Texas Register*. If there are any questions concerning this cancellation, contact Pam McDonald, TDHS, MC W-425, P.O. Box 149030, Austin, Texas 78714-9030, (512) 438- 4086.

TRD-9909060
Steve Aragón
Agency Liaison
Texas Health and Human Services Commission
Filed: December 28, 1999

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Texas Department of Housing and Community Affairs

Public Hearings for the Weatherization Assistance Program for Low-Income Persons 2000 State Plan

The Texas Department of Housing and Community Affairs (TDHCA) announces that two public hearings will be held to receive comments on the draft and the final 2000 program year state plan for the Texas Weatherization Assistance Program for Low-Income Persons.

The first public hearing will be held at 10:00 a.m. on Tuesday, January 18, 2000 in Room 118 of the Stephen F. Austin Building, 1700 North Congress Avenue, Austin, Texas. At the hearing, a representative from TDHCA will provide descriptions of the Weatherization Assistance Program (WAP) and the proposed use of the United States Department of Energy funds for the program year which begins April 1, 2000.

Local officials and citizens are encouraged to participate in the hearing process. Written and oral comments received will be used to finalize the FFY 2000 Texas Weatherization Assistance Program State Plan and Application. Written comments from those who cannot attend the hearing in person may be provided by the close of business at 5:00 p.m. on January 20, 2000 to Ms. Lolly Garcia, Senior Planner, Energy Assistance Section, Texas Department of Housing and Community Affairs, 507 Sabine, Suite 600, Austin, Texas 78701 or by electronic mail to lgarcia@tdhca.state.tx.us, or by fax to (512) 475-3935. A copy of the proposed state plan may be requested by calling Ms. Garcia at (512) 475-0471 or by writing Ms. Garcia at the TDHCA address given above. Plans will be available January 11, 2000.

The second public hearing will be held at 2:00 p.m. on Tuesday, January 25, 2000 in Room 119 of the Stephen F. Austin Building, 1700 North Congress Avenue, Austin, Texas. At the second hearing, a representative from TDHCA will provide descriptions of any changes incorporated into the final completed WAP plan. Written and oral comments received will be used to make any necessary final changes to the FFY 2000 WAP plan.

Individuals who require auxiliary aids or services for this meeting should contact Ms. Gina Esteves, ADA responsible employee, at (512) 475-3943 or Relay Texas at 1-800-735-2989 at least two days before the meeting so that appropriate arrangements can be made.

TRD-9909079
Daisy A. Stiner
Executive Director
Texas Department of Housing and Community Affairs
Filed: December 29, 1999

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Texas Department of Insurance

Insurer Services

The following applications have been filed with the Texas Department of Insurance and are under consideration:

Application for admission to the State of Texas by LEADERS LIFE INSURANCE COMPANY, a foreign life company. The home office is in Tulsa, Oklahoma.

Application to change the name of NYLCARE HEALTH PLANS OF THE SOUTHWEST, INC. to SOUTHWEST TEXAS HMO, INC., a domestic health maintenance organization. The home office is in Richardson, Texas.

Application to change the name of NYLCARE HEALTH PLANS OF THE GULF COAST, INC. to TEXAS GULF COAST HMO, INC., a domestic health maintenance organization. The home office is in Richardson, Texas.

Application to change the name of THE COLLEGE LIFE INSURANCE COMPANY OF AMERICA to AMERICO ANNUITY AND LIFE INSURANCE COMPANY, a domestic life company. The home office is in Dallas, Texas.

Application to change the name of THE VIRGINIA INSURANCE RECIPROCAL to THE RECIPROCAL GROUP, a foreign reciprocal. The home office is in Glen Allen, Virginia.

Any objections must be filed with the Texas Department of Insurance, addressed to the attention of Godwin Ohaechesi, 333 Guadalupe Street, M/C 305-2C, Austin, Texas 78701.

TRD-9909077
Bernice Ross
Deputy Chief Clerk
Texas Department of Insurance
Filed: December 29, 1999

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Texas Department of Mental Health and Mental Retardation

Public Notice Announcing Pre-application Orientation for Waiver Program Provider Enrollment

The Texas Department of Mental Health and Mental Retardation (TDMHMR), pursuant to 25 TAC §419.704, will hold a Pre-application Orientation (PAO) for persons seeking to participate as a program provider in the Home and Community-Based Services, Home and Community-Based Services-OBRA, or Mental Retardation Local Authority Programs.

The PAO will be held at 8:30 a.m., Monday, April 10, 2000, in Austin, Texas. Persons wanting to attend the PAO must request a registration form by letter or by fax. Requests should be addressed to Bill Fordyce, Enrollment/Sanctions Manager, Medicaid Administration, TDMHMR, PO Box 12668, Austin, Texas 78711-2668. The fax number is (512) 206-5725.

Upon receipt of a written request, TDMHMR will forward a registration form to the requestor. Completed registration forms must be returned to TDMHMR no later than 5:00 p.m., Friday, March 10, 2000. Written requests for a registration form received after March 5, 2000, may not be timely enough to meet the March 10, 2000, registration form return date. If the registration form is not returned to TDMHMR by March 10, 2000, the form is invalid and the applicant will be required to reapply when the next PAO is announced.

Persons with disabilities who have special communication or accommodation needs and who plan to attend the PAO and who may need auxiliary aids or services such as an interpreter for persons who are deaf or hearing impaired or readers, large print or braille for persons sight-impaired, are requested to contact Helen Rayner, Enrollment Sanctions, Medicaid Administration, TDMHMR, PO Box 12668, Austin, Texas 78711-2668, (512) 206-5249, at least two working days prior to the PAO so that appropriate arrangements can be made. You may also contact Helen Rayner for additional information concerning the PAO.

TRD-9909043
Charles Cooper
Chairman, Texas Mental Health and Mental Retardation Board
Texas Department of Mental Health and Mental Retardation
Filed: December 27, 1999

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Texas Natural Resource Conservation Commission

Notice of Amended Proposed Remedy

The executive director of the Texas Natural Resource Conservation Commission (TNRCC or Commission) is issuing this public notice of an amended proposed remedy for the Tricon America, Inc. state Superfund site. In accordance with 30 TAC §335.349(a), concerning requirements for the remedial action, and Texas Health and Safety Code, §361.187, concerning the proposed remedial action, a public meeting regarding the TNRCC's selection of an amended proposed remedy for the Tricon America, Inc. state Superfund site shall be held. The statute requires that the Commission shall publish notice of the meeting in the *Texas Register* and in a newspaper of general circulation in the county in which the facility is located at least 30 days before the date of the public meeting. This notice was also published in the *Crowley Star Review* on January 6, 2000.

The public meeting is scheduled at the Crowley City Hall, 120 North Hampton, Crowley, Texas, on Thursday, February 10, 2000, at 7:00 p.m. The public meeting will be legislative in nature and is not a contested case hearing under Texas Government Code, Chapter 2001.

The site for which a remedy is being proposed, the Tricon America, Inc. state Superfund site, was proposed for listing on the state registry of Superfund sites in the July 26, 1991 edition of the *Texas Register* (16 TexReg 4102-4103).

The Tricon site occupies approximately five acres at 101 East Hampton Road within the city limits of Crowley, Tarrant County, Texas. The property has been used as an aluminum and zinc smelting and casting operation, for the production of concrete buildings, and as a facility to assemble fiberglass buildings. An ash pile from the smelting and casting operation is the area of concern. Cadmium, chromium, and lead are the major contaminants of concerns on the site.

In March 1997, a Remedial Investigation was completed for the Tricon site to determine the nature and extent of the contamination. A Focused Feasibility Study conducted in September 1998 identified and evaluated remedial alternatives for the site. Additional sampling was performed in December 1998 to define the extent of contamination in surface and shallow subsurface soils on the Tricon facility and Deer Creek flood plain. During this additional sampling, no contaminated soil was located in the Deer Creek flood plain and no further action for this area is planned.

A Supplemental Focused Feasibility Study, dated June 1999, identified and evaluated additional remedies for the Tricon site. In the July 22, 1999 edition of the *Crowley Star Review* and the July 23, 1999 edition of the *Texas Register*, the TNRCC initially proposed Remedial Action B-2, Cap Repair and Installation of a French Drain, based on the calculated volume of the waste ash and contaminated soil. A public meeting was held on August 26, 1999, in Crowley, Texas to discuss the proposed remedy and to take public comments concerning the proposed remedy for the site.

In order to respond to issues raised at the August 26, 1999 meeting, the TNRCC conducted additional investigation to further characterize the contamination in the Triloc cap area. After a review of the results from the additional sampling, further consideration of the remedial investigation results, and consideration of the public comments received at the August 26, 1999 meeting, the TNRCC is proposing excavation and off-site disposal of the Triloc cap area waste. This alternative, shown as Alternative B-3 in the *August 1999 Proposed Remedial Action Document for Tricon America, Inc.*, is more economical and it will eliminate the need for engineering controls and future monitoring, since all contaminated materials above the action level will be removed. This recommendation is consistent with the state remedy selection criteria found in Texas Health and Safety Code, §361.193, in that it is the lowest cost alternative that is technologically feasible and reliable. It effectively mitigates and minimizes damage to, and provides protection of, the public health and safety and the environment.

Persons desiring to make comments on the amended proposed remedial action may do so at the meeting or in writing prior to the public meeting. Written comments may be submitted to Mr. Subhash Pal, P. E., TNRCC Project Manager, Remediation Division, MC 143, P.O. Box 13087, Austin, Texas 78711-3087. The public comment period for this amended proposed remedy will begin on January 6, 2000, and end at the completion of the public meeting on February 10, 2000.

The executive director of the TNRCC prepared a brief summary of the Commission's records regarding this site. This summary, and a portion of the records for this site, including documents pertinent to the proposed amended remedy, is available for review during regular business hours at the Crowley Public Library, 121 North Hampton Road, Crowley, Texas, telephone (817) 297-6707. Copies of the complete public record file may be obtained during business hours at the TNRCC, Records Management Center, Building D, North Entrance, Room 190, 12100 Park 35 Circle, Austin, Texas 78753, telephone (512) 239-2920. Photocopying of file information is subject to payment of a fee. For further information regarding this meeting or the Tricon site, please call Ms. Barbara Daywood, TNRCC Community Relations, 1-800-633-9363 (within Texas calls only) or (512) 239- 2463.

TRD-9909053
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Filed: December 28, 1999

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Notice of Availability

The Texas Natural Resource Conservation Commission (TNRCC) furnishes this notice of availability of the draft Needs Assessment for Hazardous Waste Commercial Management Capacity in Texas (2000 Update) and a 30-day period for public comment.

Notice is hereby given that the document entitled, "Needs Assessment for Hazardous Waste Commercial Management Capacity in Texas (2000 Update) (Hazardous Waste Needs Assessment)," is available for public review and comment. Section 361.0232 of the Texas Health and Safety Code requires the TNRCC to conduct an assessment of the need for commercial capacity to manage hazardous wastes generated in Texas. The Hazardous Waste Needs Assessment identifies the need for specific commercial hazardous waste management technologies. TNRCC uses information in the Hazardous Waste Needs Assessment in conjunction with rules to prioritize the TNRCC's processing of commercial hazardous waste facility permit applications. TNRCC is required by law to update the Hazardous Waste Needs Assessment every two years. The 2000 update is the fourth update to the first Needs Assessment that was published in 1992.

The public is invited to submit written comments on the draft Needs Assessment for Hazardous Waste Commercial Management Capacity in Texas (2000 Update) to TNRCC. Written comments must be received by no later than February 7, 2000. Please address written comments to: Amanda Corson, Capacity Assessment Planner, Strategic Assessment Division, TNRCC, P.O. Box 13087, MC 206, Austin, Texas 78711-3087.

Copies of the draft Needs Assessment for Hazardous Waste Commercial Management Capacity in Texas (2000 Update) can be obtained via the Internet at http://www.tnrcc.state.tx.us/oprd/wasteplan/notice.html, by contacting Amanda Corson at (512) 239-2331, or by submitting an e-mail request to capacity@tnrcc.state.tx.us.

TRD-9909050
Margaret Hoffman
Director, Environmental Law Division
Texas Natural Resource Conservation Commission
Filed: December 27, 1999

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Notice of District Application for Standby Fees

LAKE LBJ MUNICIPAL UTILITY DISTRICT OF LLANO AND BURNET COUNTIES has applied to the Texas Natural Resource Conservation Commission (TNRCC) for authority to adopt and impose an annual operations and maintenance standby fee of $34.00 per vacant lot within the District which has available water and/or wastewater facilities for calendar years 2000, 2001 and 2002. The application was filed pursuant to Chapter 49 of the Texas Water Code, 30 Texas Administrative Code Chapter 293, and under the procedural rules of the TNRCC.

The TNRCC may grant a contested case hearing on these applications if a written hearing request is filed within 30 days after the newspaper publication of this notice. The Executive Director may approve the applications unless a written request for a contested case hearing is filed within 30 days after the newspaper publication of the notice.

If a hearing request is filed, the Executive Director will not approve the application and will forward the application and hearing request to the TNRCC Commissioners for their consideration at a scheduled Commission meeting. If a contested case hearing is held, it will be a legal proceeding similar to a civil trial in state district court.

Written hearing requests should be submitted to the Office of the Chief Clerk, MC 105, TNRCC, P.O. Box 13087, Austin, TX 78711-3087. For information concerning hearing process, contact the Public Interest Counsel, MC 103, the same address. For additional information, individual members of the general public may contact the Office of Public Assistance, at 1-800-687-4040. General information regarding the TNRCC can be found at our web site at www.tnrcc.state.tx.us.

TRD-9909061
LaDonna Castañuela
Chief Clerk
Texas Natural Resource Conservation Commission
Filed: December 28, 1999

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Notice of Water Quality Applications

The following notices were issued during the period of October 21, 1999 through December 27, 1999.

The following require the applicants to publish notice in the newspaper. The public comment period, requests for public meetings, or requests for a contested case hearing may be submitted to the Office of the Chief Clerk, Mail Code 105, P O Box 13087, Austin Texas 78711-3087, WITHIN 30 DAYS OF THE DATE OF NEWSPAPER PUBLICATION OF THIS NOTICE.

CITY OF ABBOTT has applied to the Texas Natural Resource Conservation Commission (TNRCC) for a major amendment to TNRCC Permit No. 11544-001 to authorize an increase in the discharge of treated domestic wastewater from a daily average flow not to exceed 35,000 gallons per day to a daily average flow not to exceed 50,000 gallons per day. The proposed amendment also requests to construct a new wastewater treatment facility for the increased flow. The plant site is located 0.5 mile south of Farm-to-Market Road 1242 and 1.1 miles east of Interstate Highway 35 in the City of Abbott in Hill County, Texas.

AQUASOURCE DEVELOPMENT COMPANY has applied for a new permit, proposed Texas Pollutant Discharge Elimination System (TPDES) Permit No. 14114-001, to authorize the discharge of treated domestic wastewater at a daily average flow not to exceed 600,000 gallons per day. The plant site is located approximately 4.25 miles northwest of the intersection of SR- 336 Loop and Interstate Highway 46; approximately 0.25 mile east of Lake Conroe in Montgomery County, Texas.

BROCK INDEPENDENT SCHOOL DISTRICT has applied for a renewal of Permit No. 13798-001, which authorizes the disposal of treated domestic wastewater at a daily average flow not to exceed 7,500 gallons per day via evaporation and surface irrigation of 20 acres of public access land seeded primarily with bermuda grass. This permit will not authorize a discharge of pollutants into waters in the State. The wastewater treatment facilities and disposal area are located at 100 Grindstone Road, entirely within Brock Independent School District property, situated on the northwest corner of Farm-to-Market Road 1189 and an unnamed County Road and approximately 2 miles south of Interstate Highway 20 in Parker County, Texas.

CITY OF EDGEWOOD has applied for a renewal of TNRCC Permit No. 10560-001, which authorizes the discharge of treated domestic wastewater at a daily average flow not to exceed 200,000 gallons per day. The plant site is located on the southern bank Giladon Creek; approximately 2,200 feet east of Farm-to-Market Road 859 in Van Zandt County, Texas.

MARION PEVETO AND BETTY J. PEVETO has applied for a renewal of Permit No. 11316-001, which authorizes the disposal of treated domestic wastewater at a daily average flow not to exceed 12,000 gallons per day via irrigation of 18 acres of land. This permit will not authorize a discharge of pollutants into waters in the State. The wastewater treatment facilities and disposal site are located approximately 1,500 feet north of Interstate Highway 10 and 2,300 feet east of State Highway 62 in Orange County, Texas.

PORT OF HOUSTON AUTHORITY has applied for a major amendment to TNRCC Permit No. 12375-001 to authorize an increase in the discharge of treated domestic wastewater from a daily average flow not to exceed 7,000 gallons per day to a daily average flow not to exceed 22,000 gallons per day. The plant site is located at 16203 Peninsula Boulevard, approximately 3,500 feet upstream of the confluence of Carpenters Bayou and the Houston Ship Channel in Harris County, Texas.

CITY OF RALLS has applied for a renewal of Permit No. 10116-001, which authorizes the disposal of treated domestic wastewater at a daily average flow not to exceed 259,000 gallons per day via irrigation of 255 acres of land. This permit will not authorize a discharge of pollutants into waters in the State. The wastewater treatment facilities and disposal site are located near the intersection of Pecan Street and First Street; 3,000 feet southeast of the intersection of U.S. Highway 82 and State Highway 207 in Crosby County, Texas.

RANKIN ROAD WEST MUNICIPAL UTILITY DISTRICT has applied for a renewal of TNRCC Permit No. 12934-001, which authorizes the discharge of treated domestic wastewater at a daily average flow not to exceed 800,000 gallons per day. The plant site is located approximately 3,100 feet north of Spears Road and approximately 5,300 feet northeast of the intersection of Spears Road and Walters Road South in Harris County, Texas

ST. DOMINIC FISHERIES has applied for a new permit, proposed Texas Pollutant Discharge Elimination System (TPDES) Permit No. 04063, to authorize the discharge of aquaculture wastewater at a daily average flow not to exceed 2,000,000 gallons per day via Outfall 001. The applicant proposes to operate an aquaculture facility. The plant site is located three miles south of the intersection of State Highway 35 and State Highway 3280, one mile west of Farm-to-Market Road 3280, and ten miles southwest of the City of Palacios, Calhoun County, Texas.

CITY OF TEXAS CITY has applied for renewal of an existing wastewater permit. The draft permit authorizes the discharge of treated domestic wastewater at an annual average flow not to exceed 12,400,000 gallons per day. The current permit authorizes the land application of Class A sewage sludge for beneficial use and Marketing and Distribution of Class A sludge. The plant site is located approximately one mile north of State Highway Loop 197 and 4 miles east of State Highway 146, in the northeast portion of the City of Texas City in Galveston County, Texas.

TRANSWESTERN KATY FREEWAY, L.P. has applied for a renewal of TNRCC Permit No. 12406-001, which authorizes the discharge of treated domestic wastewater at a daily average flow not to exceed 12,000 gallons per day. The plant site is located approximately 400 feet south of Interstate Highway 10 (Katy Freeway) at a point 1.1 miles west of State Highway 6 and approximately 1.3 miles east of Barker-Cypress Road in Harris County, Texas.

CITY OF WEBSTER has applied for a renewal of TNRCC Permit No. 10520-001, which authorizes the discharge of treated domestic wastewater at a daily average flow not to exceed 1,650,000 gallons per day. The draft permit authorizes the discharge of treated domestic wastewater at an annual average flow not to exceed 1,650,000 gallons per day. The plant site is located at 613 Magnolia, at the east corner of the intersection of Texas Street and Magnolia Street in the City of Webster in Harris County, Texas.

Concentrated Animal Feeding Operation

Written comments and requests for a public meeting may be submitted to the Office of the Chief Clerk, WITHIN 30 DAYS OF THE DATE OF NEWSPAPER PUBLICATION OF THIS NOTICE.

DEAN CLUCK CATTLE CO., LTD. has applied to the Texas Natural Resource Conservation Commission (TNRCC) for TPDES Registration No. WQ0003795-000 to renew and replace existing authorizations to operate an existing beef cattle operation at a maximum capacity of 26,000 head in Sherman County, Texas. The application was received by TNRCC November 3, 1999. No discharge of pollutants into the waters in the state is authorized by this Registration except under chronic or catastrophic rainfall conditions. All waste and wastewater will be beneficially used on agricultural land. The existing facility is located on an unnamed road approximately one and one-half miles west of the intersection of the unnamed road and Farm-to-Market Road 1573 and this intersection being approximately three miles north of the intersection of Farm-to-Market Roads 1573 and Farm-to-Market Road 1060 in Sherman County, Texas.

TRD-9909062
LaDonna Castañuela
Chief Clerk
Texas Natural Resource Conservation Commission
Filed: December 28, 1999

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Public Utility Commission of Texas

Public Notices of Amendment to Interconnection Agreement

On December 17, 1999, Southwestern Bell Telephone Company and Now Communications, Inc., collectively referred to as applicants, filed a joint application for approval of amendment to an existing interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21871. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the amendment to the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21871. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 18, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21871.

TRD-9908992
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

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On December 17, 1999, Southwestern Bell Telephone Company and DSLnet Communications, LLC., collectively referred to as applicants, filed a joint application for approval of amendment to an existing interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21872. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the amendment to the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21872. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 18, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21872.

TRD-9908993
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

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On December 17, 1999, Southwestern Bell Telephone Company and DPI-Teleconnect, Inc., collectively referred to as applicants, filed a joint application for approval of amendment to an existing interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21873. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the amendment to the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21873. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 18, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21873.

TRD-9908994
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

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On December 20, 1999, Sprint Communications Company, L.P. and GTE Southwest, Inc., collectively referred to as applicants, filed a joint application for approval of amendment to an existing interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States

Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21879. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the amendment to the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21879. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 18, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21879.

TRD-9908995
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

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On December 20, 1999, ATS Telecommunications Systems, Inc., doing business as ATS, and GTE Southwest, Inc., collectively referred to as applicants, filed a joint application for approval of amendment to an existing interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21880. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the amendment to the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21880. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 18, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21880.

TRD-9908996
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

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On December 21, 1999, Southwestern Bell Telephone Company and TXU Communications Telecom Services Company, collectively referred to as applicants, filed a joint application for approval of amendment to an existing interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21892. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the amendment to the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21892. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 20, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21892.

TRD-9909055
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 28, 1999

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On December 21, 1999, Southwestern Bell Telephone Company and Allegiance Telecom of Texas, Inc., collectively referred to as applicants, filed a joint application for approval of amendment to an existing interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21893. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the amendment to the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21893. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 20, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21893.

TRD-9909056
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 28, 1999

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On December 22, 1999, Southwestern Bell Telephone Company and Millennium Telcom, L.L.C., collectively referred to as applicants, filed a joint application for approval of amendment to an existing interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21896. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the amendment to the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21896. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 20, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21896.

TRD-9909058
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 28, 1999

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On December 23, 1999, Southwestern Bell Telephone Company and NTS Communications, Inc., collectively referred to as applicants, filed a joint application for approval of amendment to an existing interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21904. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the amendment to the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21904. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 20, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21904.

TRD-9909059
Rhonda Dempsey

Rules Coordinator
Public Utility Commission of Texas
Filed: December 28, 1999

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Public Notices of Interconnection Agreement

On December 20, 1999, Suretel, Inc. and GTE Southwest, Inc., collectively referred to as applicants, filed a joint application for approval of interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21881. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21881. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 18, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21881.

TRD-9908997
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

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On December 20, 1999, ASAP Paging, Inc. and GTE Southwest, Inc., collectively referred to as applicants, filed a joint application for approval of interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21882. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21882. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 18, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at

(512) 936-7136. All correspondence should refer to Docket Number 21882.

TRD-9908998
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

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On December 20, 1999, Blue Star Communications, Inc. and GTE Southwest, Inc., collectively referred to as applicants, filed a joint application for approval of interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21883. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21883. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 18, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21883.

TRD-9908999
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

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On December 20, 1999, Covad Communications Company and GTE Southwest, Inc., collectively referred to as applicants, filed a joint application for approval of interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21884. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21884. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 18, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of

Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21884.

TRD-9909000
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

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On December 20, 1999, Credit Loans, Inc. doing business as Lone Star State Telephone Company and GTE Southwest, Inc., collectively referred to as applicants, filed a joint application for approval of interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21885. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21885. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 18, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21885.

TRD-9909001
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

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On December 21, 1999, Southwestern Bell Telephone Company and Phone Reconnect of America, LLC, collectively referred to as applicants, filed a joint application for approval of interconnection agreement under §252(i) of the federal Telecommunications Act of 1996, Public Law Number 104-104, 110 Statute 56, (codified as amended in scattered sections of 15 and 47 United States Code) (FTA) and the Public Utility Regulatory Act, Texas Utilities Code Annotated, Chapters 52 and 60 (Vernon 1998) (PURA). The joint application has been designated Docket Number 21894. The joint application and the underlying interconnection agreement are available for public inspection at the commission's offices in Austin, Texas.

The commission must act to approve the interconnection agreement within 35 days after it is submitted by the parties.

The commission finds that additional public comment should be allowed before the commission issues a final decision approving or rejecting the interconnection agreement. Any interested person may file written comments on the joint application by filing ten copies of the comments with the commission's filing clerk. Additionally, a copy of the comments should be served on each of the applicants. The comments should specifically refer to Docket Number 21894. As a part of the comments, an interested person may request that a public hearing be conducted. The comments, including any request for public hearing, shall be filed by January 20, 2000, and shall include:

1) a detailed statement of the person's interests in the agreement, including a description of how approval of the agreement may adversely affect those interests;

2) specific allegations that the agreement, or some portion thereof:

a) discriminates against a telecommunications carrier that is not a party to the agreement; or

b) is not consistent with the public interest, convenience, and necessity; or

c) is not consistent with other requirements of state law; and

3) the specific facts upon which the allegations are based.

After reviewing any comments, the commission will issue a notice of approval, denial, or determine whether to conduct further proceedings concerning the joint application. The commission shall have the authority given to a presiding officer pursuant to P.U.C. Procedural Rule §22.202. The commission may identify issues raised by the joint application and comments and establish a schedule for addressing those issues, including the submission of evidence by the applicants, if necessary, and briefing and oral argument. The commission may conduct a public hearing. Interested persons who file comments are not entitled to participate as intervenors in the public hearing.

Persons with questions about this project or who wish to comment on the joint application should contact the Public Utility Commission of Texas, 1701 North Congress Avenue, P. O. Box 13326, Austin, Texas 78711-3326. You may call the Public Utility Commission Office of Customer Protection at (512) 936-7120. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136. All correspondence should refer to Docket Number 21894.

TRD-9909057
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 28, 1999

♦ ♦ ♦

Notice of Application for Certificate of Operating Authority

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of an application on December 27, 1999, for a certificate of operating authority (COA), pursuant to §§54.102 - 54.105 of the Public Utility Regulatory Act (PURA). A summary of the application follows.

Docket Title and Number: Application of GTE Southwest Incorporated for a Certificate of Operating Authority, Docket Number 21903 before the Public Utility Commission of Texas.

Applicant intends to provide a full range of telecommunications service, including, but not limited to, local exchange service, basic local telecommunications service, toll service and access service, custom calling services, advanced data services, and other optional services based on customer demand.

Applicant's requested COA geographic area includes the entire state of Texas currently served by Southwestern Bell Telephone Company.

Persons who wish to comment upon the action sought should contact the Public Utility Commission of Texas at P.O. Box 13326, Austin, Texas 78711-3326, or call the commission's Office of Customer Protection at (512) 936-7120 no later than January 12, 2000. Hearing and speech-impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136.

TRD-9909065
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 29, 1999

♦ ♦ ♦

Notices of Application for Service Provider Certificate of Operating Authority

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of an application on December 20, 1999, for a service provider certificate of operating authority (SPCOA), pursuant to §§54.151 - 54.156 of the Public Utility Regulatory Act (PURA). A summary of the application follows.

Docket Title and Number: Application of USA Quick Phone, Inc. for a Service Provider Certificate of Operating Authority, Docket Number 21876 before the Public Utility Commission of Texas.

Applicant intends to provide the resale of plain old telephone service, Digital Subscriber Line, ISDN, T-1 Private Line, Switch 56 KBPS, and Fractional T-1 services.

Applicant's requested SPCOA geographic area includes the entire state of Texas.

Persons who wish to comment upon the action sought should contact the Public Utility Commission of Texas at P.O. Box 13326, Austin, Texas 78711-3326, or call the commission's Office of Customer Protection at (512) 936-7120 no later than January 12, 2000. Hearing and speech-impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136.

TRD-9909002
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 22, 1999

♦ ♦ ♦

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of an application on December 21, 1999, for a service provider certificate of operating authority (SPCOA), pursuant to §§54.151 - 54.156 of the Public Utility Regulatory Act (PURA). A summary of the application follows.

Docket Title and Number: Application of FairPoint Communications Corporation for a Service Provider Certificate of Operating Authority, Docket Number 21895 before the Public Utility Commission of Texas.

Applicant intends to provide plain old telephone service, Digital Subscriber Line, T1-Private Line, Switch 56 KBPS, Frame Relay, Fractional T1, and long distance services.

Applicant's requested SPCOA geographic area includes the entire state of Texas.

Persons who wish to comment upon the action sought should contact the Public Utility Commission of Texas at P.O. Box 13326, Austin, Texas 78711-3326, or call the commission's Office of Customer Protection at (512) 936-7120 no later than January 12, 2000. Hearing and speech-impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136.

TRD-9909047
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 27, 1999

♦ ♦ ♦

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of an application on December 22, 1999, for a service provider certificate of operating authority (SPCOA), pursuant to §§54.151 - 54.156 of the Public Utility Regulatory Act (PURA). A summary of the application follows.

Docket Title and Number: Application of Arrival Communications, Inc. for a Service Provider Certificate of Operating Authority, Docket Number 21901 before the Public Utility Commission of Texas.

Applicant intends to provide plain old telephone service, Digital Subscriber Line, ISDN, T1- Private Line, Switch 56 KBPS, Frame Relay, Fractional T1, and long distance services.

Applicant's requested SPCOA geographic area includes the geographic area served by all incumbent local exchange companies throughout the state of Texas.

Persons who wish to comment upon the action sought should contact the Public Utility Commission of Texas at P.O. Box 13326, Austin, Texas 78711-3326, or call the commission's Office of Customer Protection at (512) 936-7120 no later than January 12, 2000. Hearing and speech-impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136.

TRD-9909048
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 27, 1999

♦ ♦ ♦

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of an application on December 23, 1999, for a service provider certificate of operating authority (SPCOA), pursuant to §§54.151 - 54.156 of the Public Utility Regulatory Act (PURA). A summary of the application follows.

Docket Title and Number: Application of Concentric Carrier Services, Inc. for a Service Provider Certificate of Operating Authority, Docket Number 21902 before the Public Utility Commission of Texas.

Applicant intends to provide plain old telephone service, Digital Subscriber Line, ISDN, T1–Private Line, Switch 56 KBPS, Frame Relay, Fractional T1, and long distance services.

Applicant's requested SPCOA geographic area includes the entire state of Texas.

Persons who wish to comment upon the action sought should contact the Public Utility Commission of Texas at P.O. Box 13326, Austin, Texas 78711-3326, or call the commission's Office of Customer Protection at (512) 936-7120 no later than January 12, 2000. Hearing and speech-impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136.

TRD-9909063
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 28, 1999

♦ ♦ ♦

Notice of Application of Texas Alltel, Inc. *et.al* to Provide One-Way, Optional, Extended Metropolitan Calling Service

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of a joint agreement on September 3, 1999, seeking approval of one-way, optional, Extended Metropolitan Calling Service (EMCS) from the Scurry/Rosser Exchange to the Dallas Metropolitan Exchange and the Crandall Exchange pursuant to P.U.C. Substantive Rule §23.49(b)(8).

Project Title and Number: Application of Texas Alltel, Inc. and Southwestern Bell Telephone Company *et.al.*, to Provide One-Way, Optional, Extended Metropolitan Calling Service, Pursuant to P.U.C. Substantive Rule §23.49(b)(8), Docket Number 21318.

The Joint Petition and Agreement: The proposed plan is an optional offering to which subscribing Texas Alltel, Inc. customers residing within the telephone exchange boundaries of the Scurry/Rosser exchange will be able to call Southwestern Bell Telephone Company's Dallas metropolitan exchange and the Crandall exchange.

The joint applicants have requested that the joint agreement filing be processed administratively pursuant to P.U.C. Substantive Rule §23.49(b)(8)(C). Persons who wish to intervene in the proceeding or comment upon action sought should contact the Public Utility Commission of Texas by mail at P.O. Box 13326, Austin, Texas, 78711-3326, or call the Public Utility Commission Office of Customer Protection Division at (512) 936-7120 by March 7, 2000. Hearing and speech-impaired individuals with text telephones (TTY) may contact the commission at (512) 936-7136.

TRD-9909051
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 27, 1999

♦ ♦ ♦

Notice of Application to Amend Certificate of Convenience and Necessity

Notice is given to the public of the filing with the Public Utility Commission of Texas (commission) of an application on December 22, 1999, to amend a certificate of convenience and necessity pursuant to §§14.001, 37.051, and 37.054, 37.056, 37.057 of the Public Utility Regulatory Act, Texas Utilities Code Annotated (Vernon 1998) (PURA). A summary of the application follows.

Docket Style and Number: Application of Southwestern Electric Power Company (SWEPCO) to Amend a Certificate of Convenience and Necessity for a Proposed Transmission Line within Gregg and Harrison Counties. Docket Number 21900.

The Application: SWEPCO proposes to build a single circuit 138 kV transmission line approximately 9.86 miles in length, which will run generally west to east from SWEPCO's existing Harrison Road Substation to a new EASTEX Switching Station, adjacent to the Texas Eastman Plant. A copy of the amended application and additional associated maps are available for reviewing at the SWEPCO office, 209 South Center Street, Longview, Texas. Persons with questions about this project should contact Keith Honey at (903) 234-7351.

Persons who wish to comment upon the action sought should contact the Public Utility Commission of Texas at P. O. Box 13326, Austin, Texas 78711-3326, or call the commission's Office of Customer Protection at (512) 936-7120 or (888) 782-8477. Hearing and speech-impaired individuals with text telephone (TTY) may contact the commission at (512) 936-7136 or use Relay Texas (toll-free) 1-800-735-2989. The deadline for intervention in the proceeding will be established, but will be no earlier than February 7, 2000. The commission should receive a letter requesting intervention on or before that date.

TRD-9909049
Rhonda Dempsey
Rules Coordinator
Public Utility Commission of Texas
Filed: December 27, 1999

♦ ♦ ♦

Center for Rural Health Initiatives

Request for Proposal

The Center for Rural Health Initiatives is issuing a Request for Proposals ("RFP") for Rural Health Network Development under the Medicare Rural Flexibility Program in the State of Texas. The purpose of this RFP is to provide the applicant with the information necessary to apply for grant funds under the provisions of this program.

The purpose of this program is to create a turnkey program, consisting of tools and templates, that assist rural hospitals in forming vital and successful rural health networks.

USE OF FUNDS: The funds can be used to research successful models, explore the benefits of networks in rural areas, create the hardcopy and software versions of the final product, develop a training program and create an assessment tool.

AMOUNT OF AWARD: The funding available for the support of this program during FY 2000 is $35,000. Only one proposal will be funded.

ELIGIBLE APPLICANTS: Eligible applicants will include non-profit and for-profit organizations; including academic institutions, professional associations and other entities.

EVALUATION AND SELECTION: After an initial screening for eligibility and completeness, remaining applications will be reviewed by the Program Administrator and the Executive Director. The CAH Ad-Hoc Committee will also be given an opportunity to make recommendations to the Executive Director, who will make a final recommendation to Executive Committee of CRHI. The Executive Committee has the sole authority to make the final decision. The review of the proposals will be based upon the breadth of the proposed program, the number of stakeholders the models involve and the degree to which the models developed can be applied to different communities. Also, reviewers will look at the extent and ease of training, the utility of the tools and templates created, the evaluation of the success of the models created and the effective and efficient use of the funds available.

DEADLINE: Completed applications are due by February 15, 2000. Announcement of the selected applicant will be made by February 29, 2000.

CONTRACT PERIOD: The budget period for the application funded under this RFP will be April 1, 2000 - September 30, 1999.

CONTACT PERSON: To obtain the application, please contact: David Pearson, Program Administrator, Center for Rural Health Initiatives, P.O. Drawer 1708, Austin, Texas, 78767-1708, (512)479-8891

TRD-9909071
Robert J. "Sam" Tessen
Executive Director
Center for Rural Health Initiatives
Filed: December 29, 1999

♦ ♦ ♦

Texas Workers' Compensation Commission

Correction of Error

The Texas Workers' Compensation Commission (TWCC) published the adoption of new 28 TAC §132.16 in the December 17, 1999, issue of the *Texas Register* (24 TexReg 11452).

Due to agency error:

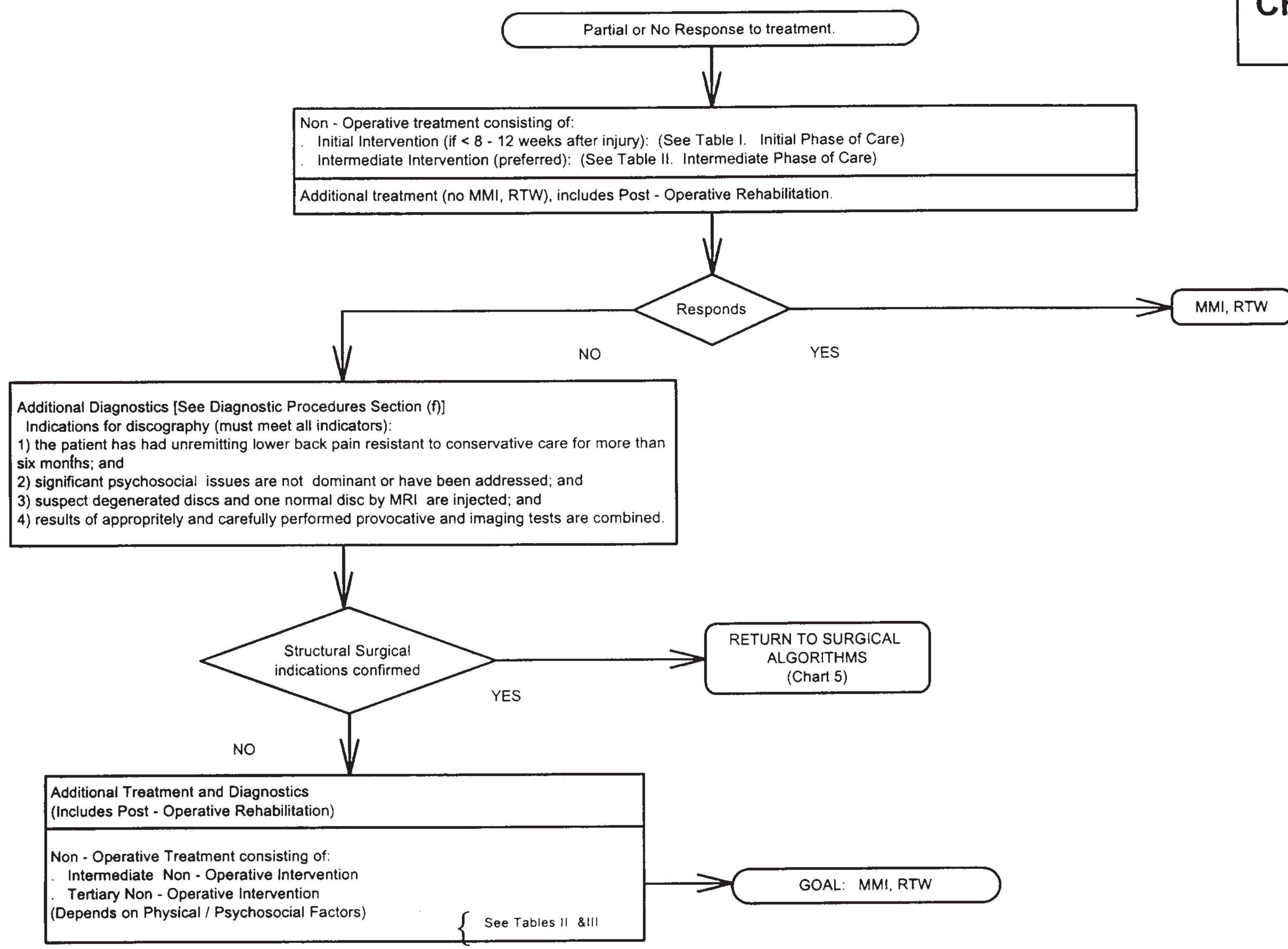
On page 11454, right column, paragraph (d)(1), the word "in" should be deleted and the paragraph should read as follows: (1) Monthly death benefit payments shall be initiated no later than the 45th day after the date on which the written agreement was approved by the Commission.

In addition, TWCC published adopted amendments to §134.1001 in the December 17, 1999, issue of the *Texas Register* (24 TexReg 11455).

On page 11566, Chart 6 (labeled Figure: 28 TAC §134.1001(i)(6)) is missing the second box. This box should follow the box which says "Partial or No Response to treatment" and should read as follows:

Texas Workers' Compensation Commission Figure: 28TAC §134.1001(i)(6)

CHART 6



How to Use the Texas Register

Information Available: The 13 sections of the ***Texas Register*** represent various facets of state government. Documents contained within them include:

Governor - Appointments, executive orders, and proclamations.

Attorney General - summaries of requests for opinions, opinions, and open records decisions.

Secretary of State - opinions based on the election laws.

Texas Ethics Commission - summaries of requests for opinions and opinions.

Emergency Rules- sections adopted by state agencies on an emergency basis.

Proposed Rules - sections proposed for adoption.

Withdrawn Rules - sections withdrawn by state agencies from consideration for adoption, or automatically withdrawn by the Texas Register six months after the proposal publication date.

Adopted Rules - sections adopted following a 30-day public comment period.

Texas Department of Insurance Exempt Filings - notices of actions taken by the Texas Department of Insurance pursuant to Chapter 5, Subchapter L of the Insurance Code.

Texas Department of Banking - opinions and exempt rules filed by the Texas Department of Banking.

Tables and Graphics - graphic material from the proposed, emergency and adopted sections.

Open Meetings - notices of open meetings.

In Addition - miscellaneous information required to be published by statute or provided as a public service.

Review of Agency Rules - notices of state agency rules review.

Specific explanation on the contents of each section can be found on the beginning page of the section. The division also publishes cumulative quarterly and annual indexes to aid in researching material published.

How to Cite: Material published in the ***Texas Register*** is referenced by citing the volume in which the document appears, the words "TexReg" and the beginning page number on which that document was published. For example, a document published on page 2402 of Volume 24 (1999) is cited as follows: 24 TexReg 2402.

In order that readers may cite material more easily, page numbers are now written as citations. Example: on page 2 in the lower-left hand corner of the page, would be written "23 TexReg 2 issue date," while on the opposite page, page 3, in the lower right-hand corner, would be written "issue date 23 TexReg 3."

How to Research: The public is invited to research rules and information of interest between 8 a.m. and 5 p.m. weekdays at the ***Texas Register*** office, Room 245, James Earl Rudder Building, 1019 Brazos, Austin. Material can be found using ***Texas Register*** indexes, the ***Texas Administrative Code***, section numbers, or TRD number.

Both the ***Texas Register*** and the ***Texas Administrative Code*** are available online through the Internet. The address is: http://www.sos.state.tx.us. The ***Register*** is available in an .html version as well as a .pdf (portable document format) version through the Internet. For subscription information, see the back cover or call the Texas Register at (800) 226-7199.

Texas Administrative Code

The ***Texas Administrative Code*** (***TAC***) is the compilation of all final state agency rules published in the ***Texas Register***. Following its effective date, a rule is entered into the ***Texas Administrative Code***. Emergency rules, which may be adopted by an agency on an interim basis, are not codified within the ***TAC***.

The ***TAC*** volumes are arranged into Titles (using Arabic numerals) and Parts (using Roman numerals). The Titles are broad subject categories into which the agencies are grouped as a matter of convenience. Each Part represents an individual state agency.

The complete TAC is available through the Secretary of State's website at http://www.sos.state.tx.us. The following companies also provide complete copies of the TAC: Lexis-Nexis (1-800-356-6548), LOIS, Inc. (1-800-364-2512 ext. 152), and West Publishing Company (1-800-328-9352).

The Titles of the ***TAC***, and their respective Title numbers are:

1. Administration
4. Agriculture
7. Banking and Securities
10. Community Development
13. Cultural Resources
16. Economic Regulation
19. Education
22. Examining Boards
25. Health Services
28. Insurance
30. Environmental Quality
31. Natural Resources and Conservation
34. Public Finance
37. Public Safety and Corrections
40. Social Services and Assistance
43. Transportation

How to Cite: Under the ***TAC*** scheme, each section is designated by a ***TAC*** number. For example in the citation 1 TAC §27.15:

1 indicates the title under which the agency appears in the ***Texas Administrative Code***; ***TAC*** stands for the ***Texas Administrative Code***; §27.15 is the section number of the rule (27 indicates that the section is under Chapter 27 of Title 1; 15 represents the individual section within the chapter).

How to update: To find out if a rule has changed since the publication of the current supplement to the ***Texas Administrative Code***, please look at the ***Table of TAC Titles Affected***. The table is published cumulatively in the blue-cover quarterly indexes to the ***Texas Register*** (January 8, April 9, July 9, and October 8, 1999). If a rule has changed during the time period covered by the table, the rule's ***TAC*** number will be printed with one or more ***Texas Register*** page numbers, as shown in the following example.

TITLE 40. SOCIAL SERVICES AND ASSISTANCE

Part I. Texas Department of Human Services

40 TAC §3.704..............950, 1820

The ***Table of TAC Titles Affected*** is cumulative for each volume of the ***Texas Register*** (calendar year).

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