ELECTRIC GENERATING UNIT (EGU) STANDARD PERMIT REGISTRATION

Port of Brownsville Energy Complex

Element H2GEN, LLC / Brownsville, TX

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Project 234404.0237

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1. INTRODUCTION

Element H2GEN, LLC (H2GEN) has acquired property in Brownsville, Cameron County, Texas and plans to construct and operate an electric generating power plant to generate power for sale. H2GEN is submitting this Air Quality Standard Permit for Electric Generating Units permit registration, to authorize the construction of the proposed electrical generating facility.

1.1 Purpose of This Application

The purpose of this standard permit registration is to authorize the installation and operation of two combined cycle power generating units, Trains 1 and 2 (EPNs T1 and T2), each of which will contain one gas-fired combustion turbine generator (CTG) and one heat recovery steam generator (HRSG) with supplemental gas-fired duct burners.

Facilities and emissions authorized with this permit registration include emissions from combustion turbine normal operation, maintenance start up and shutdown (MSS) operation, turbine lube oil vents, and fugitive equipment. Additional ancillary emissions sources will be authorized separately under Permit by Rule (PBR) claims (see Section 4.2 for additional details).

Table 1-1 at the end of this Section presents a summary of the project sources and emission rates. Table 6-1 in Section 6 presents the project emissions compared to Prevention of Significant Deterioration (PSD) applicability thresholds. The project emissions are below the major source thresholds for all pollutants; therefore, PSD permitting requirements do not apply.

1.2 Application Organization

The enclosed Standard Permit registration is organized into the following sections:

Section 1	contains background information about the planned project.
Section 2	describes the administrative forms and fee payment included with this submittal.
Section 3	contains an area map and a plot plan.
Section 4	contains a general process description and process flow diagram.
Section 5	describes the emission calculation methods used for the project.
Section 6	addresses Federal New Source Review applicability.
Section 7	addresses the applicability and general conditions for an EGU Standard Permit as specified in 30 TAC § 116.610, § 116.615, and Air Quality Standard Permit for Electric Generating Units (Effective Date: May 16, 2007).
Appendix A	contains emissions calculation details.
Appendix B	contains administrative forms.
Appendix C	contains a copy of the Electric Generating Unit Standard Permit

Table 1-1. Project Emission Summary

EPN	Source Name	Pollutant	Proposed Emissions lb/hr	Proposed Emissions tpy
T1	Train 1	NOx	10.76	26.34
		NOx (MSS)	168.16	
		CO	13.10	25.52
		CO (MSS)	43.09	
		VOC	10.31	37.73
		PM	4.99	18.31
		PM_{10}	4.99	18.31
		$PM_{2.5}$	4.99	18.31
		SO_2	5.11	3.74
		NH_3	9.96	36.43
OIL1	Turbine Oil Mist	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
T2	Train 2	NOx	10.76	26.34
		NOx (MSS)	168.16	
		CO	13.10	25.52
		CO (MSS)	43.09	
		VOC	10.31	37.73
		PM	4.99	18.31
		PM_{10}	4.99	18.31
		$PM_{2.5}$	4.99	18.31
		SO_2	5.11	3.74
		NH_3	9.96	36.43
OIL2	Turbine Oil Mist	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
FUG	Fugitive Emissions	VOC	0.01	0.05
		NH_3	0.01	0.04

2. ADMINISTRATIVE FORMS

The following TCEQ forms and tables are included with this submittal in Appendix B:

- Core Data Form
- PI-1S, Registration of Air Standard Permit
- Table 1(a), Emission Point Summary
- Table 1F, Air Quality Application Supplement
- Table 2F, Project Emission Increase Supplement (VOC)
- Table 2F, Project Emission Increase Supplement (NOx)
- Table 2F, Project Emission Increase Supplement (CO)
- Table 2F, Project Emission Increase Supplement ($PM/PM_{10}/PM_{2.5}$)
- Table 2F, Project Emission Increase Supplement (SO_2)

In accordance with 30 TAC § 116.614, there is a flat fee of $900 to register a standard permit. This fee has been paid online.

3. PROJECT LOCATION

The Port of Brownsville Energy Complex is located at 17600 RL Ostos Road in Brownsville, Cameron County, Texas. An area map is shown in Figure 3-1. Figure 3-2 presents the preliminary design location of proposed emission sources to be authorized under this Standard Permit.

NORTH

Source: Google Earth
Zone: R14

PORT OF BROWNSVILLE

REFERENCE DRAWINGS	NO.	REVISION	DRWN	CHKD	APRVD	DATE
	B	ISSUED FOR DESIGN	BB	CS	LM	19 JULY 24
	A	ISSUED FOR REVIEW	BB	CS	LM	12 JULY 24

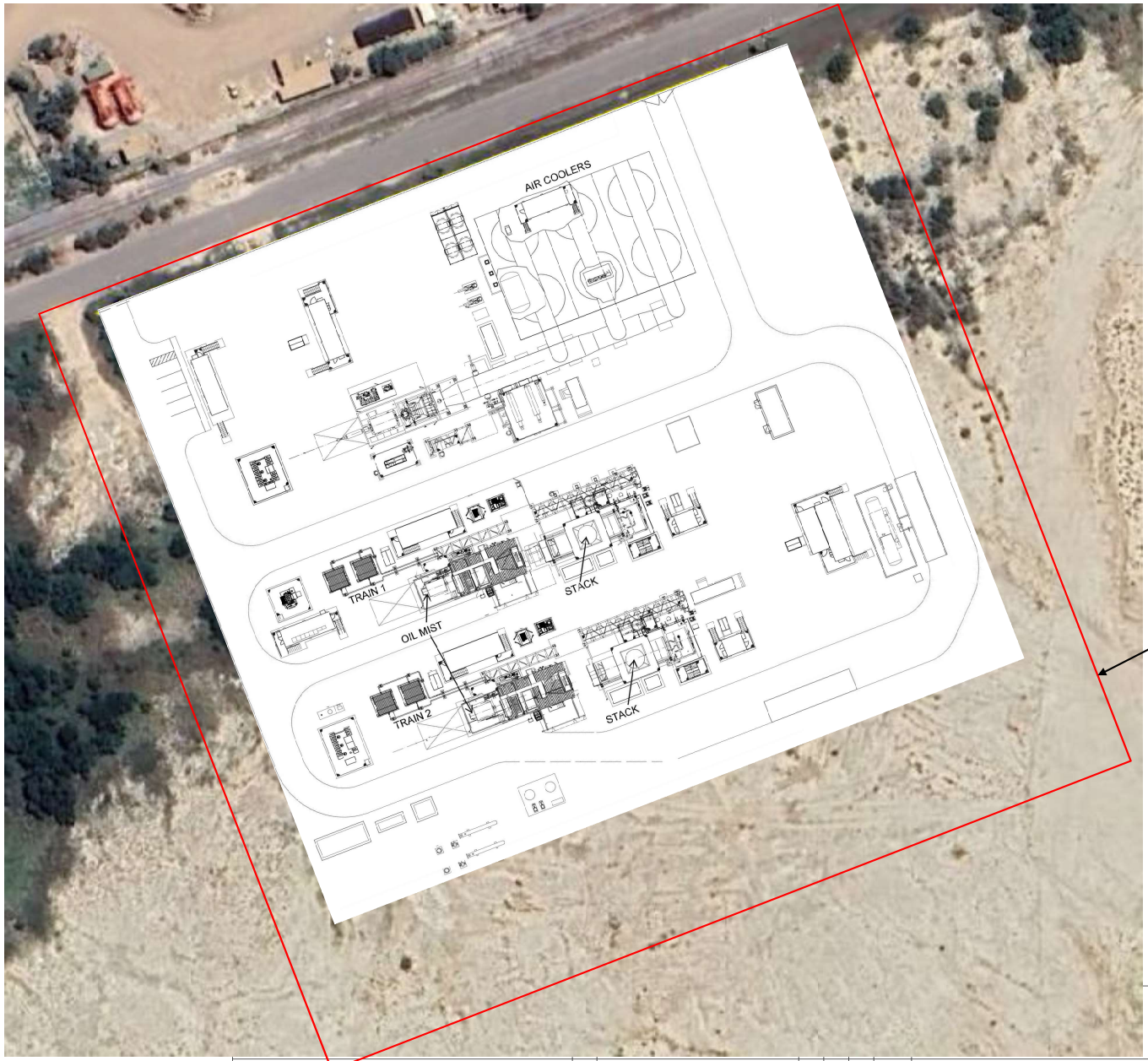
Drawn By	Drwn Date	Chkd By	Chkd Date	Aprvd By	Aprvd Date	Scale
BB	10 JULY 24	CS	10 JULY 24	LM	10 JULY 24	NONE

ELEMENT H2Gen
UNIT 505 – COMBINE CYCLE POWER PLANT

Figure 3-1. Area Map

FOR:

PROJECT NUMBER	DRAWING NUMBER:	REVISION
	CCP-GN-505-PM-PLS-0001	B



REFERENCE DRAWINGS	NO.	REVISION	DRWN	CHKD	APRVD	DATE
	B	ISSUED FOR DESIGN	BB	CS	LM	19 JULY 24
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Drawn By	Drwn Date	Chkd By	Chkd Date	Aprvd By	Aprvd Date	Scale
BB	10 JULY 24	CS	10 JULY 24	LM	10 JULY 24	NONE

ELEMENT H2Gen
UNIT 505 – COMBINE CYCLE POWER PLANT

Figure 3-2. Plot Plan

FOR:

PROJECT NUMBER	DRAWING NUMBER:	REVISION
	CCP-GN-505-PM-PLS-0001	B

4. PROCESS DESCRIPTION

4.1 Power Generation

The proposed facility will be a combined cycle power plant consisting of two units, Trains 1 and 2, each of which will contain one gas-fired combustion turbine generator (CTG) and one heat recovery steam generator (HRSG) with supplemental gas-fired duct burners. Each CTG will be nominally rated at 62 megawatts (MW) of electrical power. Trains 1 and 2 feed one steam turbine generator, which will produce up to roughly 90 MW of electric power.

The main function of the CTGs is to provide shaft power to drive an electric generator. Combustion air and natural gas are fed to each combustor producing a high-velocity combustion discharge that impinges on the turbine blades to rotate the turbine shaft. The hot exhaust gas exits the turbine and is routed to the HRSG for steam production. The mechanical energy produced by the CTG is used to drive the electric generator and to compress inlet air.

The turbine shaft speed is monitored and used to control the fuel flow to the turbine. In turn, the fuel flow defines the turbine operating conditions. The fuel-to-air ratio is controlled by the physical dimensions of the combustor. Therefore, as the fuel demand changes, the combustion air flow changes accordingly. Normal operation of the CTG is base load, but the turbines will be capable of operating at various loads. The CTG exhaust gases are vented to the atmosphere through the HRSG stack. Product of combustion emissions including nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM), and sulfur dioxide (SO_2) are formed through fuel combustion.

The HRSGs use hot combustion gas exiting the CTGs and supplemental natural gas firing of the duct burners to produce steam. The amount of steam generated is proportional to the CTG exhaust parameters and the heat added by the duct burners. Emissions of NOx from the turbines will be reduced using selective catalytic reduction (SCR) controls on the HRSG stacks (EPNs T1 and T2). Oxidation catalyst may be used to reduced CO emissions. Ammonia (NH_3) emissions may occur due to slip of excess ammonia from the SCR system.

The steam turbine generator (STG) will receive steam from either or both HRSGs. As the steam flows past the STG's blades, the steam expands and cools. The thermal energy from the steam is turned into mechanical energy in the rotating STG's blades. The turbine is connected to a generator, which in turn produces energy via a magnetic field that produces an electric current.

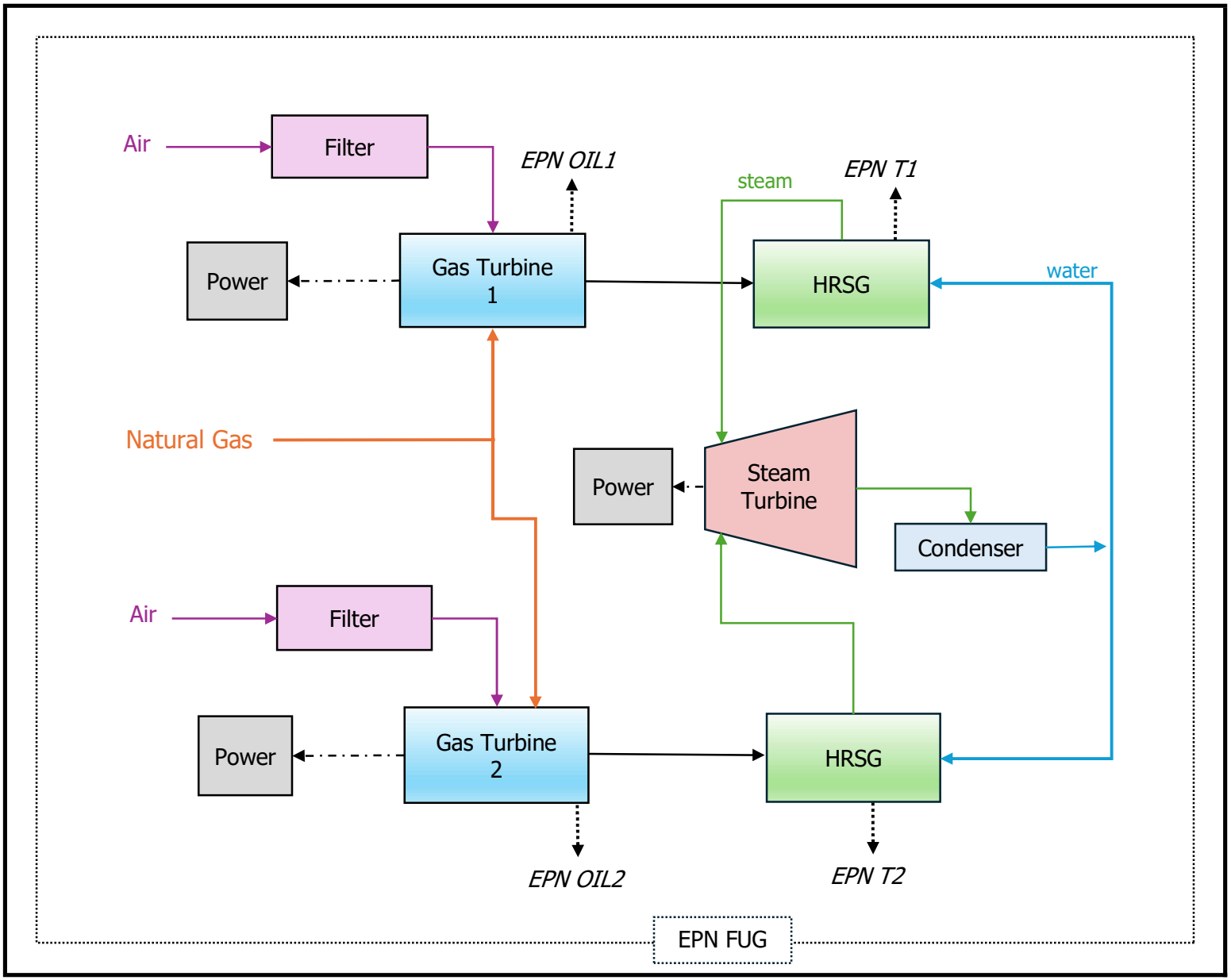
Gas turbines consume oil to lubricate and cool the compressor and turbine bearings. Lube oil continuously circulates throughout the gas turbine assembly, and a supply of lube oil is maintained in a reservoir within the assembly. Leaks of lube oil (which would foul the turbine blades) will be prevented through the use of "seal air," which is bled from the compressor and supplied to the exterior of the bearing boxes, creating a lower pressure in the interior of the bearing boxes than in their supporting part. High-pressure seal air becomes dissolved in the circulating lube oil, and eventual deaeration in the lube oil reservoir gives rise to a fine mist of lube oil from the vent of the reservoir (EPNs OIL1 and OIL2). This mist evaporates and then enters the ambient air, resulting in VOC emissions.

A simplified process flow diagram is provided as Figure 4-1.

4.2 Ancillary Equipment

Ancillary equipment and emission sources at the site may include a diesel-fired generator and/or firewater pump and water storage tanks. Waste oil generated during normal operations may be collected and separated via an oil water separator. Waste oil will be periodically collected and may be disposed of offsite using frac tanks and vacuum trucks. Other inherently low emitting maintenance activities that could occur include but are not limited to; turbine water washing, intake filter maintenance and disposal, SCR catalyst handling, and fugitive piping equipment maintenance and replacement. Emissions from miscellaneous ancillary equipment and inherently low emitting maintenance activities will be authorized separate of this registration via claims of Permit by Rule (PBR) including §106.263, §106.472, §106.511 and §106.532.

Figure 4-1. Simplified Process Flow Diagram



5. EMISSION CALCULATION METHODS

The following describes the calculation methodologies utilized to determine the emission rates from each facility type included in this application. Detailed emission calculations are provided in Appendix A.

5.1 Turbines & Duct Burners

Emissions from the turbines and HRSG duct burners (EPNs T1 and T2) are based on the proposed firing rates and emission factors as described below.

Routine emissions of NOx, CO, VOC, and NH_3 slip are calculated using stack concentration limits and the calculation method described in equation 19-1 from EPA Method 19 guidance[1], along with the dry F (Fd) factor for natural gas. The concentration limits are given as parts per million by volume, dry (ppmvd), corrected to 15% oxygen (O_2). The turbine(s) will be equipped with selective catalytic reduction (SCR) controls to reduce emissions of NOx. Short-term (hourly) emissions of NOx and CO are conservatively represented at twice the annual basis concentration to allow for occasional emission rate fluctuations. NH_3 emissions may occur due to slip of excess ammonia from the SCR system. Emissions of ammonia slip are based on a stack concentration of 10 ppmvd at 15% oxygen.

Emissions of PM, including particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$), from the turbines are calculated using emission factors from *Compilation of Air Pollutant Emission Factors: Volume I Stationary Point and Area Sources*, Fifth Edition (hereafter referred to in this application as AP-42) Table 3.1-2a. Emissions of $PM/PM_{10}/PM_{2.5}$ from the duct burner are calculated using emission factors from AP-42 Table 1.4-2.

SO_2 emissions are also calculated using the emission factor from Table 1.4-2 of AP-42. The AP-42 factor is adjusted following footnote (d) of Table 1.4-2 to reflect a natural gas sulfur fuel content of 5 grains (gr) per 100 standard cubic feet (scf) on an hourly basis and 1 gr/100 scf on an annual basis. Formation of sulfuric acid (H_2SO_4) is anticipated to be negligible based on the low sulfur content of the fuel and has therefore not been quantified.

Higher concentrations of NOx and CO may be generated during periods of maintenance, startup, and shutdown (MSS) on the turbines. Estimated MSS emissions are calculated using the uncontrolled emission factors from AP-42 Table 3.1-1. The turbines are expected to operate at reduced loads during MSS; however, the emission calculations are conservatively estimated using the routine capacity and heat rate. Annual MSS emissions are calculated based on 100 hours per year of MSS operation. The MSS hours and emission factors are for calculation purposes only and are not intended to be operational restrictions. H2GEN will comply with the represented annual emissions presented on Table 1a.

5.2 Turbine Oil Mist

Oil mist emissions are estimated using a mass balance approach and conservatively assuming that approximately 0.01 gallons per day of lubricating oil is used by each turbine and that all the oil is emitted as VOC and PM. The density of No. 6 Fuel Oil from Table 7.1-2 of AP-42 is assumed as a representative basis for the oil used.

[1] https://www.epa.gov/sites/default/files/2017-08/documents/method_19.pdf [version dated 3/29/2023]

If the turbines stop operation and the lube oil temperature drops, lube oil mist is not being produced and the mist eliminators may be shut down. During this time, breathing and refilling losses may occur from each oil reservoir. However, these losses will be negligible compared to the emissions during the recirculation of the hot lube oil.

5.3 Equipment Leak Fugitives

The fugitive emissions from piping components and ancillary equipment are estimated using methods outlined in the TCEQ's guidance web page for Equipment Leak Fugitives. Each fugitive component is classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). Consistent with permitting for other similar facilities, the emission factors for Oil & Gas Production Operations have been applied for non-SCR system components. The calculated emission rate is then multiplied by the concentration of VOC to obtain the VOC emission rate. Components associated with the SCR system are calculated using SCOMI without ethylene factors and the audio, visual, olfactory (AVO) Leak Detection and Repair (LDAR) program control efficiencies.

6. FEDERAL NEW SOURCE REVIEW

Federal Prevention of Significant Deterioration (PSD) and/or Nonattainment New Source Review (NNSR) permitting requirements apply to construction of a new major stationary source or modification of an existing major source that results in a significant net increase in emissions of a regulated air pollutant. The proposed facility will be a new source located in Cameron County, which is designated as attainment or unclassifiable for all criteria pollutants (i.e., principal pollutants with a National Ambient Air Quality Standard (NAAQS)). Therefore, NNSR permitting requirements are not applicable to the proposed project.

The proposed facility will be a PSD "named" stationary source and will therefore have a major source threshold of 100 tons per year (tpy) of any regulated pollutant. As shown below, the proposed project increases for all PSD program pollutants are less than the PSD major source threshold; therefore, the project is not subject to PSD permitting requirements. PSD review is not required for greenhouse gas (GHG) emissions because the project does not trigger PSD review for any other pollutants.

Table 6-1. PSD Applicability Summary

Pollutant	Project Increase (tpy)	Major Threshold (tpy)	Federal Review Required (Yes/No)
NOx	52.67	100	No
CO	51.04	100	No
VOC	75.52	100	No
PM	36.63	100	No
PM_{10}	36.63	100	No
$PM_{2.5}$	36.63	100	No
SO_2	7.48	100	No
NH_3	72.91	n/a	No

7. RULE APPLICABILITY ANALYSIS

This section addresses the applicability and general conditions of a Standard Permit. The applicability and general conditions of an Air Quality Standard Permit for Electric Generating Units are discussed in Section 6.2.

7.1 30 Texas Administrative Code (TAC) 116 Subchapter F

7.1.1 30 TAC 116.610 (Applicability)

(a) Under the Texas Clean Air Act, §382.051, a project that meets the requirements for a standard permit listed in this subchapter or issued by the commission is hereby entitled to the standard permit, provided the following conditions listed in this section are met. For the purposes of this subchapter, project means the construction or modification of a facility or a group of facilities submitted under the same registration.

(1) Any project that results in a net increase in emissions of air contaminants from the project other than water, nitrogen, ethane, hydrogen, oxygen, or greenhouse gases (GHGs) as defined in §101.1 of this title (relating to Definitions), or those for which a national ambient air quality standard has been established must meet the emission limitations of §106.261 of this title (relating to Facilities (Emission Limitations)), unless otherwise specified by a particular standard permit.

This requirement is not applicable per item (3)(A) of the Air Quality Standard Permit for Electric Generating Units.

(2) Construction or operation of the project must be commenced prior to the effective date of a revision to this subchapter under which the project would no longer meet the requirements for a standard permit.

The project will meet the requirements of the standard permit in effect at the time of the construction or operation.

(3) The proposed project must comply with the applicable provisions of the Federal Clean Air Act (FCAA), §111 (concerning New Source Performance Standards) as listed under 40 Code of Federal Regulations (CFR) Part 60, promulgated by the United States Environmental Protection Agency (EPA).

The turbines will comply with applicable requirements of New Source Performance Standards (NSPS) as listed in 40 CFR Part 60 Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) and Subpart TTTTa (Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units).

The turbines will fire natural gas with a maximum heating value >50 MMBtu and ≤ 850 MMBtu. The turbines will comply with the following Subpart KKKK emissions limits summarized below.

- ***NOx: 25 ppmvd @ 15% O2***
- ***SO2: < 20 grains of sulfur per 100 standard cubic feet, or <0.06 lb SO2/MMBtu***

Turbines proposed in this permit registration utilize SCR to reduce NOx emissions. H2GEN will install calibrate and maintain a continuous emissions monitoring system

to monitor NOx emissions. H2GEN will comply with the fuel sulfur requirements using valid purchase contract, tariff or transportation contract under §60.4365(a). H2GEN will comply with all excess emissions and monitor downtime reporting requirements outlined under §60.7(c).

(4) The proposed project must comply with the applicable provisions of FCAA, §112 (concerning Hazardous Air Pollutants) as listed under 40 CFR Part 61, promulgated by the EPA.

The proposed sources will not be subject to National Emissions Standards for Hazardous Air Pollutants (NESHAP) Subparts as listed in 40 CFR Part 61.

(5) The proposed project must comply with the applicable maximum achievable control technology standards as listed under 40 CFR Part 63, promulgated by the 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 Part 63)).

The H2GEN facility will be an area source of HAP emissions and therefore not subject to requirements under NESHAPS for Source Categories as listed in 40 CFR Part 63 (aka MACT) Subpart YYYY (National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines).

(6) If subject to Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program) the proposed facility, group of facilities, or account must obtain allocations to operate.

Cameron County is not regulated under the Mass Emissions Cap and Trade (MECT) program.

(b) Any project that constitutes a new major stationary source or major modification as defined in §116.12 of this title (relating to Nonattainment and Prevention of Significant Deterioration Review Definitions) because of emissions of air contaminants other than greenhouse gases is subject to the requirements of §116.110 of this title (relating to Applicability) rather than this subchapter. Notwithstanding any provision in any specific standard permit to the contrary, any project that constitutes a new major stationary source or major modification which is subject to Subchapter B, Division 6 of this chapter (relating to Prevention of Significant Deterioration Review) due solely to emissions of greenhouse gases may use a standard permit under this chapter for air contaminants that are not greenhouse gases.

As documented in Section 6, the proposed project does not constitute a new major source or major modification.

(c) Persons may not circumvent by artificial limitations the requirements of §116.110 of this title.

H2GEN will not circumvent by artificial limitations the requirements of §116.110.

(d) Any project involving a proposed affected source (as defined in §116.15(1) of this title (relating to Section 112(g) Definitions)) shall comply with all applicable requirements under Subchapter E of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)). Affected sources subject to Subchapter E of this chapter may use a standard permit under this subchapter only if the terms and conditions of the specific standard permit meet the requirements of Subchapter E of this chapter.

The Port of Brownsville Energy Complex is not an affected source subject to the requirements of FCAA 112(g).

7.1.2 30 TAC 116.615 (General Conditions)

The following general conditions are applicable to holders of standard permits, but will not necessarily be specifically stated within the standard permit document.

(1) Protection of public health and welfare. The emissions from the facility, including dockside vessel emissions, must comply with all applicable rules and regulations of the commission adopted under Texas Health and Safety Code, Chapter 382, and with the intent of the Texas Clean Air Act (TCAA), including protection of health and property of the public.

All emissions related to this project will comply with all applicable rules and regulations, including protection of health and property of the public.

(2) Standard permit representations. All representations with regard to construction plans, operating procedures, pollution control methods, and maximum emission rates in any registration for a standard permit become conditions upon which the facility or changes thereto, must be constructed and operated. It is unlawful for any person to vary from such representations if the change will affect that person's right to claim a standard permit under this section. Any change in condition such that a person is no longer eligible to claim a standard permit under this section requires proper authorization under §116.110 of this title (relating to Applicability). Any changes in representations are subject to the following requirements:

(A) For the addition of a new facility, the owner or operator shall submit a new registration incorporating existing facilities with a fee, in accordance with §116.611 and §116.614 of this title, (relating to Registration to use a Standard Permit and Standard Permit Fees) prior to commencing construction. If the applicable standard permit requires public notice, construction of the new facility or facilities may not commence until the new registration has been issued by the executive director.

(B) For any change in the method of control of emissions, a change in the character of the emissions, or an increase in the discharge of the various emissions, the owner or operator shall submit written notification to the executive director describing the change(s), along with the designated fee, no later than 30 days after the change.

(C) For any other change to the representations, the owner or operator shall submit written notification to the executive director describing the change(s) no later than 30 days after the change.

(D) Any facility registered under a standard permit which contains conditions or procedures for addressing changes to the registered facility which differ from subparagraphs (A) - (C) of this paragraph shall comply with the applicable requirements of the standard permit in place of subparagraphs (A) - (C) of this paragraph.

H2GEN will operate the proposed EGU equipment as represented in this application and will notify the TCEQ within 30 days of any change in the method of control of emissions, a change in the character of the emissions, or an increase in the discharge of the various emissions as compared to the representations in this registration.

(3) Standard permit in lieu of permit amendment. All changes authorized by standard permit to a facility previously permitted under §116.110 of this title shall be administratively incorporated into that facility's permit at such time as the permit is amended or renewed.

This is an initial authorization for the Port of Brownsville Energy Complex; there is no existing authorization under 30 TAC 116.

(4) Construction progress. Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office not later than 15

working days after occurrence of the event, except where a different time period is specified for a particular standard permit.

H2GEN will comply with this provision.

(5) Start-up notification.

(A) The appropriate air program regional office of the commission and any other air pollution control agency having jurisdiction shall be notified prior to the commencement of operations of the facilities authorized by a standard permit in such a manner that a representative of the executive director may be present.

(B) For phased construction, which may involve a series of units commencing operations at different times, the owner or operator of the facility shall provide separate notification for the commencement of operations for each unit.

(C) Prior to beginning operations of the facilities authorized by the permit, the permit holder shall identify to the Office of Permitting, Remediation, and Registration, the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program).

(D) A particular standard permit may modify start-up notification requirements.

H2GEN will comply with this provision.

(6) Sampling requirements. If sampling of stacks or process vents is required, the standard permit holder shall contact the commission's appropriate regional office and any other air pollution control agency having jurisdiction prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The standard permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant.

H2GEN will contact the Office of Air Quality if sampling is required, in order to obtain the proper data forms and procedures before sampling is performed.

(7) Equivalency of methods. The standard permit holder shall demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the standard permit. Alternative methods must be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the standard permit.

H2GEN will comply with this provision.

(8) Recordkeeping. A copy of the standard permit along with information and data sufficient to demonstrate applicability of and compliance with the standard permit shall be maintained in a file at the plant site and made available at the request of representatives of the executive director, the United States Environmental Protection Agency, or any air pollution control agency having jurisdiction. For facilities that normally operate unattended, this information shall be maintained at the nearest staffed location within Texas specified by the standard permit holder in the standard permit registration. This information must include, but is not limited to, production records and operating hours. Additional recordkeeping requirements may be specified in the conditions of the standard permit. Information and data sufficient to demonstrate applicability of and compliance with the standard permit must be retained for at least two years following the date that the information or data is obtained. The copy of the standard permit must be maintained as a permanent record.

H2GEN will maintain a copy of the standard permit with any other data and information required by the TCEQ to demonstrate compliance with the conditions of the standard permit at the Port of Brownsville Energy Complex or H2GEN's administrative offices for at least two years after the data is obtained. This information will be provided upon request to representatives of the TCEQ and any federal or local air pollution control program having jurisdiction.

(9) Maintenance of emission control. The facilities covered by the standard permit may not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. Notification for emissions events and scheduled maintenance shall be made in accordance with §101.201 and §101.211 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; and Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements).

The EGU equipment will be maintained in good working order and operated properly during normal operations. TCEQ will be notified of any emissions events and scheduled maintenance consistent with the requirements of §101.201 and §101.211.

(10) Compliance with rules. Registration of a standard permit by a standard permit applicant constitutes an acknowledgment and agreement that the holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the claiming of the standard permit. If more than one state or federal rule or regulation or permit condition are applicable, the most stringent limit or condition shall govern. Acceptance includes consent to the entrance of commission employees and designated representatives of any air pollution control agency having jurisdiction into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the standard permit.

As discussed in this Section and in Section 7.2, the project sources will comply with all applicable rules and regulations of the TCEQ and with all conditions of this standard permit.

(11) Distance limitations, setbacks, and buffer zones. Notwithstanding any requirement in any standard permit, if a standard permit for a facility requires a distance, setback, or buffer from other property or structures as a condition of the permit, the determination of whether the distance, setback, or buffer is satisfied shall be made on the basis of conditions existing at the earlier of:

(A) the date new construction, expansion, or modification of a facility begins; or

(B) the date any application or notice of intent is first filed with the commission to obtain approval for the construction or operation of the facility.

The standard permit claimed does not include a distance, setback, or buffer requirement.

7.2 Air Quality Standard Permit for Electric Generating Units

(Effective Date: May 16, 2007)

This standard permit authorizes electric generating units that generate electricity for use by the owner or operator and/or generate electricity to be sold to the electric grid, and that meet all of the conditions listed below.

7.2.1 (1) Applicability

(A) This standard permit may be used to authorize electric generating units installed or modified after the effective date of this standard permit and that meet the requirements of this standard permit.

This Standard Permit is being used to authorize an electric generating unit after the effective date of the standard permit. The project meets the requirements of the Standard Permit as described in this document.

(B) This standard permit may not be used to authorize boilers. Boilers may be authorized under the Air Quality Standard Permit for Boilers; 30 TAC § 106.183, Boilers, Heaters, and Other Combustion Devices; or a permit issued under the requirements of 30 TAC Chapter 116.

No boilers are proposed to be authorized as part of this registration.

7.2.2 (2) Definitions

(A) East Texas Region - All counties traversed by or east of Interstate Highway 35 or Interstate Highway 37, including Bosque, Coryell, Hood, Parker, Somervell and Wise Counties.

(B) Installed - a generating unit is installed on the site when it begins generating electricity.

(C) West Texas Region - Includes all of the state not contained in the East Texas Region.

(D) Renewable fuel - fuel produced or derived from animal or plant products, byproducts or wastes, or other renewable biomass sources, excluding fossil fuels. Renewable fuels may include, but are not limited to, ethanol, biodiesel, and biogas fuels.

The above definitions have been acknowledged and applied in this document.

7.2.3 (3) Administrative Requirements

(A) Electric generating units shall be registered in accordance with 30 TAC § 116.611, Registration to Use a Standard Permit, using a current Form PI-1S. Units that meet the conditions of this standard permit do not have to meet 30 TAC § 116.610(a)(1), Applicability.

This application, including Form PI-1S, is being submitted to register the proposed electric generating unit under the Standard Permit. Compliance with the requirements of § 116.611 is detailed in Section 7.1.1.

(B) Registration applications shall comply with 30 TAC § 116.614, Standard Permit Fees, for any single unit or multiple units at a site with a total generating capacity of 1 megawatt (MW) or greater. The fee for units or multiple units with a total generating capacity of less than 1 MW at a site shall be $100.00. The fee shall be waived for units or multiple units with a total generating capacity of less than 1 MW at a site that have certified nitrogen oxides (NOx) emissions that are less than 10 percent of the standards required by this standard permit.

This application is being submitted with the standard $900 fee per § 116.614. The project does not qualify for a reduced fee based on the proposed generating capacity.

(C) No owner or operator of an electric generating unit shall begin construction and/or operation without first obtaining written approval from the executive director.

H2GEN acknowledges that construction and operation may not begin prior to receiving written approval from TCEQ.

(D) Records shall be maintained and provided upon request to the Texas Commission on Environmental Quality (TCEQ) for the following:

(i) Hours of operation of the unit;

(ii) Maintenance records, maintenance schedules, and/or testing reports for the unit to document re-certification of emission rates as required by subsection (4)(G) below; and

(iii) Records to document compliance with the fuel sulfur limits in subsection (4)(C).

H2GEN will maintain records necessary to demonstrate compliance with the Standard Permit, including the specific records identified above.

(E) Electric generators powered by gas turbines must meet the applicable conditions, including testing and performance standards, of Title 40 Code of Federal Regulations (CFR) Part 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, and applicable requirements of 40 CFR Part 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.

H2GEN will comply with the requirements of 40 CFR 60 (NSPS) Subpart KKKK. Per §60.4305(b), turbines regulated under Subpart KKKK are exempt from the requirements of Subpart GG.

(F) Compliance with this standard permit does not exempt the owner or operator from complying with any applicable requirements of 30 TAC Chapter 117, Control of Air Pollution from Nitrogen Compounds, or 30 TAC Chapter 114, Control of Air Pollution from Motor Vehicles.

Cameron County is not subject to the requirements of Chapter 117, including Subchapters D or E. Facilities included in this application are not subject to requirements of 30 TAC Chapter 114 for motor vehicles.

7.2.4 (4) General Requirements

(A) Emissions of NOx from the electric generating unit shall be certified by the manufacturer or by the owner or operator in pounds of pollutant per megawatt hour (lb/MWh). This certification must be displayed on the name plate of the unit or on a label attached to the unit. Test results from U.S. Environmental Protection Agency (EPA) reference methods, California Air Resources Board methods, or equivalent alternative testing methods approved by the executive director used to verify this certification shall be provided upon request to the TCEQ. The unit must operate on the same fuel(s) for which the unit was certified.

H2GEN will comply with this provision.

(B) Electric generating units that use combined heat and power (CHP) may take credit for the heat recovered from the exhaust of the combustion unit to meet the emission standards in subsections (4)(D), (4)(E), and (4)(F). Credit shall be at the rate of one MWh for each 3.4 million British Thermal Units of heat recovered. The following requirements must be met to take credit for CHP for units not sold and certified as an integrated package by the manufacturer:

(i) The owner or operator must provide as part of the application documentation of the heat recovered, electric output, efficiency of the generator alone, efficiency of the generator including CHP, and the use for the non-electric output, and

(ii) The heat recovered must equal at least 20 percent of the total energy output of the CHP unit.

This application is not seeking to take credit for CHP to meet the emission standard in Subsection (4)(E).

(C) Fuels combusted in these electric generating units are limited to:

(i) Natural gas containing no more than ten grains total sulfur per 100 dry standard cubic feet;

(ii) Landfill gas, digester gas, stranded oilfield gas, or gaseous renewable fuel containing no more than 30 grains total sulfur per 100 dry standard cubic feet; or

(iii) Liquid fuels (including liquid renewable fuel) not containing waste oils or solvents and containing less than 0.05 percent by weight sulfur.

The proposed project involves the use of natural gas fuel meeting item (i).

(D) Except as provided in subsections (4)(F) and (4)(H), NOx emissions for units 10 MW or less shall meet the following limitations based upon the date the unit is installed and the region in which it operates:

East Texas Region:

(i) Units installed prior to January 1, 2005 and

a. operating more than 300 hours per year - 0.47 lb/MWh;

b. operating 300 hours or less per year - 1.65 lb/MWh;

(ii) Units installed on or after January 1, 2005 and

a. operating more than 300 hours per year, with a capacity greater than 250 kilowatts (kW) - 0.14 lb/MWh;

b. operating 300 hours or less per year - 0.47 lb/MWh; or

c. any unit with a capacity of 250 kW or less - 0.47 lb/MWh.

West Texas Region:

(i) Units operating more than 300 hours per year - 3.11 lb/MWh;

(ii) Units operating 300 hours or less per year - 21 lb/MWh. Units certified to comply with applicable Tier 1, 2, or 3 emission standards in 40 CFR Part 89, Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines, are deemed to satisfy this emission limit.

The proposed units are greater than 10MW; therefore, this section does not apply.

(E) Except as provided in subsections (4)(F) and (4)(H), NOx emissions for units greater than 10 MW shall meet the following limitations:

(i) Units operating more than 300 hours per year - 0.14 lb/MWh;

(ii) Units operating 300 hours or less per year - 0.38 lb/MWh.

The NOx will not exceed 0.14 lb/MWh for units operating more than 300 hours per year. The turbines will comply with this hourly average limitation at all times when the ambient air temperature is above 0 degrees Fahrenheit and when the units are operating above 80% of rated load. At less than 80% load conditions, the NOx emissions in lb/hr will not exceed the mass emission rate equivalent of this standard at full load conditions.

(F) Electric generating units firing any gaseous or liquid fuel that is at least 75 percent landfill gas, digester gas, stranded oil field gas, or renewable fuel content by volume, shall meet a NOx emission limit of 1.90 lb/MWh. Units in West Texas with a capacity of 10 MW or less that fire at least 75 percent landfill gas, digester gas, stranded oilfield gases, or gaseous or liquid renewable fuel by volume, must comply with the applicable West Texas NOx limit in subsection (4)(D).

The proposed project involves the use of natural gas fuel only.

(G) To ensure continuing compliance with the emissions limitations, the owner or operator shall re-certify a unit every 16,000 hours of operation, but no less frequently than every three years. Re-certification may be accomplished by following a maintenance schedule that the manufacturer certifies will ensure continued compliance with the required NOx standard or by third party testing of the unit using appropriate EPA reference methods, California Air Resources Board methods, or equivalent alternative testing methods approved by the executive director to demonstrate that the unit still meets the required emission standards. After re-certification, the unit must operate on the same fuel(s) for which the unit was re-certified.

H2GEN will comply with this provision. Compliance with the NOx emission standards will be demonstrated through the use of a continuous emissions monitoring system (CEMS). The CEMS will undergo initial certification followed by quarterly and annual quality assurance tests.

(H) The NOx emission limits in subsections (4)(D)-(4)(F) are subject to the following exceptions:

(i) The hourly NOx emission limits do not apply at times when the ambient air temperature at the location of the unit is less than 0 degrees Fahrenheit.

(ii) At times when a unit is operating at less than 80% of rated load, an alternative NOx emission standard for that unit may be determined by multiplying the applicable emission standard in subsections (4)(D)-(4)(F) by the rated load of the EGU (in MW), to produce an allowable hourly mass NOx emission rate. In order to use this alternative standard, an owner or operator must maintain records that demonstrate compliance with the alternative emission standard, and make such records available to the TCEQ or any local air pollution control agency with jurisdiction upon request.

H2GEN understands the NOx emission exceptions specified above. The facility will maintain records to support any NOx emissions above the limit in subsection (4)(D) that is allowed under this subsection.

APPENDIX A. EMISSION CALCULATIONS

Table A-1
Combustion Turbine Emissions (EPNs T1 & T2)
Element H2GEN LLC
July 2024

Basis:
- Emissions are calculated using design data and other published factors, as specified below.

Standard Volume:	385.2	scf/lbmol
NG Fuel F-Factor:	8710	dscf/MMBtu
Annual Operation:	8760	hours/yr
MSS Hours:	100	hours/yr

	Parameter	Value		Unit	Basis
		Hourly	Annual		
Turbine	Fuel Type	Natural Gas			
	Fuel HHV	1,020	1,020	Btu/scf	AP-42 standard value
	Capacity	69.3	62.4	MW (HHV)	design basis (per GT)
	Heat Rate	7,584	6,825	Btu/kW-hr(HHV)	design basis
	PM	6.60E-03	6.60E-03	lb/MMBtu	AP-42 Table 3.1-2a
	NOx (MSS)	3.20E-01	3.20E-01	lb/MMBtu	AP-42 Table 3.1-1
	CO (MSS)	8.20E-02	8.20E-02	lb/MMBtu	AP-42 Table 3.1-1
Duct Burner	Heat Input	204.6	184.1	MMBtu/hr (HHV)	design basis (per DB)
	Fuel Type	Natural Gas			
	Fuel HHV	1,020	1,020	Btu/scf	AP-42 standard value
	PM	0.0075	0.0075	lb/MMBtu	AP-42 Table 1.4-2
Turbine + Duct Burner	NOx	4	2	ppmv, dry 15%O_2	BACT (annual)
	CO	8	4	ppmv, dry 15%O_2	BACT (annual)
	VOC (as propane)	4	4	ppmv, dry 15%O_2	BACT (w/ Duct Burner)
	SO_2	5	1	gr S/100 dscf fuel	BACT
	NH_3	10	10	ppmv, dry 15%O2	BACT
Plant Gross Output	Power Generation	213.5	192.2	MW	Two Trains

Turbine Estimated Emissions						
Pollutant	Factor (lb/MMBtu)		Firing Rate (MMBtu/hr)		Emissions (per EPN)	
	Hourly	Annual	Hourly	Annual	lb/hr	tpy
NOx	0.0147	0.0074	525	426	7.75	13.74
(at 8660 hours/yr)						13.58
CO	0.0179	0.0090			9.43	16.73
(at 8660 hours/yr)						16.54
VOC	0.0141	0.0141			7.42	26.34
PM	0.0066	0.0066			3.47	12.30
SO_2	0.0070	0.0014			3.68	2.61
NH_3	0.0136	0.0136			7.17	25.43
NOx (MSS)	0.3200	0.3200			168.16	6.81
CO (MSS)	0.0820	0.0820			43.09	1.75

Table A-1
Combustion Turbine Emissions (EPNs T1 & T2)
Element H2GEN LLC
July 2024

Duct Burner Estimated Emissions						
Pollutant	Factor (lb/MMBtu)		Firing Rate (MMBtu/hr)		Emissions (per EPN)	
	Hourly	Annual	Hourly	Annual	lb/hr	tpy
NOx	0.0147	0.0074	205	184	3.02	5.94
CO	0.0179	0.0090			3.67	7.24
VOC	0.0141	0.0141			2.89	11.39
PM	0.0075	0.0075			1.52	6.01
SO_2	0.0070	0.0014			1.43	1.13
NH_3	0.0136	0.0136			2.79	11.00

Turbine + Duct Buner Estimated Emissions						
Pollutant	Factor (lb/MMBtu)		Firing Rate (MMBtu/hr)		Emissions (per EPN)	
	Hourly	Annual	Hourly	Annual	lb/hr	tpy
NOx	0.0147	0.0099	730	610	10.76	26.34
CO	0.0179	0.0096			13.10	25.52
VOC	0.0141	0.0141			10.31	37.73
PM	0.0068	0.0069			4.99	18.31
SO_2	0.0070	0.0014			5.11	3.74
NH_3	0.0136	0.0136			9.96	36.43

NOx and CO annual emissions represent the higher of 8760 hr/yr routine operation or 100 hr/yr MSS operation + 8660 hr/yr routine operation

Sample Calculations

Turbine Emissions *(annual emission basis)*

NOx Factor = $\frac{2 \text{ parts}}{1{,}000{,}000 \text{ parts}} \left| \frac{8710 \text{ dscf}}{\text{MMBtu}} \right| \frac{\text{lb-mol}}{385 \text{ dscf}} \left| \frac{(20.9\% - 0\%)}{(20.9\% - 15\%)} \right| \frac{46.0 \text{ lb}}{\text{lb-mol}} = 0.007 \frac{\text{lb NOx}}{\text{MMBtu}}$

CO Factor = $\frac{4 \text{ parts}}{1{,}000{,}000 \text{ parts}} \left| \frac{8710 \text{ dscf}}{\text{MMBtu}} \right| \frac{\text{lb-mol}}{385 \text{ dscf}} \left| \frac{(20.9\% - 0\%)}{(20.9\% - 15\%)} \right| \frac{28.0 \text{ lb}}{\text{lb-mol}} = 0.009 \frac{\text{lb CO}}{\text{MMBtu}}$

VOC Factor = $\frac{4 \text{ parts}}{1{,}000{,}000 \text{ parts}} \left| \frac{8710 \text{ dscf}}{\text{MMBtu}} \right| \frac{\text{lb-mol}}{385 \text{ dscf}} \left| \frac{(20.9\% - 0\%)}{(20.9\% - 15\%)} \right| \frac{44.1 \text{ lb}}{\text{lb-mol}} = 0.014 \frac{\text{lb VOC}}{\text{MMBtu}}$

NH3 Factor = $\frac{10 \text{ parts}}{1{,}000{,}000 \text{ parts}} \left| \frac{8710 \text{ dscf}}{\text{MMBtu}} \right| \frac{\text{lb-mol}}{385 \text{ dscf}} \left| \frac{(20.9\% - 0\%)}{(20.9\% - 15\%)} \right| \frac{17.0 \text{ lb}}{\text{lb-mol}} = 0.014 \frac{\text{lb VOC}}{\text{MMBtu}}$

SO2 Factor = $\frac{1 \text{ gr}}{100 \text{ scf}} \left| \frac{1 \text{ lb}}{7000 \text{ gr}} \right| \frac{\text{scf}}{1020 \text{ Btu}} \left| \frac{1{,}000{,}000 \text{ Btu}}{\text{MMBtu}} \right| = 0.001 \frac{\text{lb SO2}}{\text{MMBtu}}$

Turbine = $\frac{69 \text{ MW}}{} \left| \frac{7584 \text{ Btu}}{\text{kW-hr}} \right| \frac{1 \text{ kW} \cdot \text{MMBtu}}{1000 \text{ MW} \cdot \text{Btu}} = 525 \frac{\text{MMBtu}}{\text{hr}}$

NOx Emissions = $\frac{.0147 \text{ lb}}{\text{MMBtu}} \left| \frac{525 \text{ MMBtu}}{\text{hr}} \right| = 7.75 \frac{\text{lb NOx}}{\text{hr}}$

Duct Burner Emissions

NOx Emissions = $\frac{.007 \text{ lb}}{\text{MMBtu}} \left| \frac{184 \text{ MMBtu}}{\text{hr}} \right| \frac{8{,}760 \text{ hours}}{\text{yr}} \left| \frac{\text{ton}}{2{,}000 \text{ lb}} \right| = 5.94 \frac{\text{ton NOx}}{\text{yr}}$

Table A-2
Lube Oil Vent Emissions
Element H2GEN LLC
July 2024

Basis:

- Emissions are calculated using a mass balance approach and assuming that all oil used is counted both as VOC and PM
- Calculations apply the density of No. 6 Fuel Oil from AP-42 Table 7.1-2.

Oil Usage Rate per Vent (gal/day)	Oil Density (lb/gal)	Annual Operation (days/yr)	Emissions per Turbine	
			lb/hr	tpy
0.01	7.9	365	0.003	0.002

Sample Calculations:

$$\frac{.01\ \text{lb}}{\text{day}} \times \frac{7.90\ \text{lb}}{\text{gal}} \times \frac{\text{day}}{24\ \text{hours}} = 0.003\ \frac{\text{lb}}{\text{hr}}$$

$$\frac{.01\ \text{lb}}{\text{day}} \times \frac{365\ \text{days}}{\text{yr}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} = 0.002\ \frac{\text{ton}}{\text{yr}}$$

Table A-3
Fugitive Component Emissions
Element H2GEN LLC
July 2024

Basis:

- Emissions are calculated using the fugitive emission factors and LDAR control efficiencies found on TCEQ's Air Permit Technical Guidance for Chemical Sources Fugitive Guidance (APDG 6422) dated June 2018.

Natural Gas Components

Component Type	Service	Component Count	Oil & Gas Production Operations (lb/hr-component)	% VOC	VOC Emissions lb/hr	VOC Emissions tpy
Valves	G/V	100	0.00992	0.81%	0.0081	0.0354
Flanges	G/V	250	0.00086		0.0018	0.0077
Relief Valves	G/V	8	0.0194		0.0013	0.0055
Pumps	G/V	2	0.00529		0.0001	0.0004
				Total =	**0.01**	**0.05**

SCR System Piping Fugitives

Component Type	Service	Component Count	SOCMI w/o C2 (lb/hr-component)	AVO LDAR	NH3 Emissions lb/hr	NH3 Emissions tpy
Valves	LL	15	0.0035	97%	0.0016	0.0069
Flanges	LL	38	0.0005	97%	0.0006	0.0025
Relief Valves	LL	1	0.2293	97%	0.0069	0.0301
Pumps	LL	0	0.0386	93%	0.0000	0.0000
				Total =	**0.01**	**0.04**

Sample Calculations:

Valves in G/V service: 100 components x 0.00992 lb/hr-component x 0.81% VOC = 0.0081 lb/hr VOC

APPENDIX B. ADMINISTRATIVE FORMS

TCEQ Use Only

TCEQ Core Data Form

For detailed instructions on completing this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission (*If other is checked please describe in space provided.*)

☒ New Permit, Registration or Authorization (*Core Data Form should be submitted with the program application.*)

☐ Renewal (*Core Data Form should be submitted with the renewal form*) ☐ Other

2. Customer Reference Number *(if issued)*	Follow this link to search for CN or RN numbers in Central Registry**	**3. Regulated Entity Reference Number** *(if issued)*
CN		**RN**

SECTION II: Customer Information

4. General Customer Information	**5. Effective Date for Customer Information Updates** (mm/dd/yyyy)	7/11/2024

☒ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership

☐ Change in Legal Name (Verifiable with the Texas Secretary of State or Texas Comptroller of Public Accounts)

The Customer Name submitted here may be updated automatically based on what is current and active with the Texas Secretary of State (SOS) or Texas Comptroller of Public Accounts (CPA).

6. Customer Legal Name *(If an individual, print last name first: eg: Doe, John)* *If new Customer, enter previous Customer below:*

Element H2GEN, LLC

7. TX SOS/CPA Filing Number	**8. TX State Tax ID** (11 digits)	**9. Federal Tax ID** (9 digits)	**10. DUNS Number** *(if applicable)*
805621228	32095893577	99-1642784	

11. Type of Customer: ☐ Corporation ☐ Individual Partnership: ☐ General ☐ Limited

Government: ☐ City ☐ County ☐ Federal ☐ Local ☐ State ☐ Other ☐ Sole Proprietorship ☒ Other: Limited Liability Company

12. Number of Employees ☐ 0-20 ☒ 21-100 ☐ 101-250 ☐ 251-500 ☐ 501 and higher

13. Independently Owned and Operated? ☒ **Yes** ☐ **No**

14. Customer Role (Proposed or Actual) – *as it relates to the Regulated Entity listed on this form. Please check one of the following*

☐ Owner ☐ Operator ☒ Owner & Operator ☐ Other:
☐ Occupational Licensee ☐ Responsible Party ☐ VCP/BSA Applicant

15. Mailing Address:	16051 Addison Rd., Suite 207						
	City	Addison	**State**	TX	**ZIP**	75001	**ZIP + 4**	5367

16. Country Mailing Information *(if outside USA)*	**17. E-Mail Address** *(if applicable)*
	info@elementfuels.com

18. Telephone Number	**19. Extension or Code**	**20. Fax Number** *(if applicable)*
(713) 589-5102		( ) -

SECTION III: Regulated Entity Information

21. General Regulated Entity Information *(If 'New Regulated Entity" is selected, a new permit application is also required.)*

☒ New Regulated Entity ☐ Update to Regulated Entity Name ☐ Update to Regulated Entity Information

The Regulated Entity Name submitted may be updated, in order to meet TCEQ Core Data Standards (removal of organizational endings such as Inc, LP, or LLC).

22. Regulated Entity Name *(Enter name of the site where the regulated action is taking place.)*

Port of Brownsville Energy Complex

23. Street Address of the Regulated Entity: ***(No PO Boxes)***	17600 RL Ostos Road							
	City	Brownsville	**State**	TX	**ZIP**	78521	**ZIP + 4**	
24. County	Cameron							

If no Street Address is provided, fields 25-28 are required.

25. Description to Physical Location:					
26. Nearest City			**State**		**Nearest ZIP Code**

Latitude/Longitude are required and may be added/updated to meet TCEQ Core Data Standards. (Geocoding of the Physical Address may be used to supply coordinates where none have been provided or to gain accuracy).

27. Latitude (N) In Decimal:	25.9611668		**28. Longitude (W) In Decimal:**	-97.358574	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
25	57	40	97	21	31

29. Primary SIC Code (4 digits)	**30. Secondary SIC Code** (4 digits)	**31. Primary NAICS Code** (5 or 6 digits)	**32. Secondary NAICS Code** (5 or 6 digits)
4911		22111	

33. What is the Primary Business of this entity? *(Do not repeat the SIC or NAICS description.)*

electric power generation

34. Mailing Address:	**16051 Addison Rd., Suite 207**							
	City	**Addison**	**State**	**TX**	**ZIP**	**75001**	**ZIP + 4**	**5367**
35. E-Mail Address:	**info@elementfuels.com**							

36. Telephone Number	**37. Extension or Code**	**38. Fax Number** *(if applicable)*
(713) 519-5102		**( ) -**

39. TCEQ Programs and ID Numbers Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Emissions Inventory Air	☐ Industrial Hazardous Waste
☐ Municipal Solid Waste	☒ New Source Review Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS
☐ Sludge	☐ Storm Water	☐ Title V Air	☐ Tires	☐ Used Oil
☐ Voluntary Cleanup	☐ Wastewater	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name:	Robin Patrick	**41. Title:**	Managing Consultant

42. Telephone Number	**43. Ext./Code**	**44. Fax Number**	**45. E-Mail Address**
(737 **)** 284-0641		**( ) -**	robin.patrick@trinityconsultants.com

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 6 and/or as required for the updates to the ID numbers identified in field 39.

Company:	Element H2GEN, LLC	**Job Title:**	CEO
Name *(In Print):*	John Calce	**Phone:**	**(** 214 **)** 725- **9818**
Signature:		**Date:**	07/22/24

Form PI-1S
Registrations for Air Standard Permit
(Page 1)
Texas Commission on Environmental Quality

I. Registrant Information
A. Company or Other Legal Customer Name:
Element H2GEN, LLC
B. Company Official Contact Information (☒ Mr. ☐ Mrs. ☐ Ms. ☐ Other:)_____
Name: Thomas Ramsey
Title: Chief Commercial Officer
Mailing Address: 24 Greenway Plaza, Suite 405
City: Houston
State: TX
ZIP Code: 77046
Telephone No.: 832-763-1900
Fax No.:
Email Address: tom.ramsey@elementfuels.com
All permit correspondence will be sent via email. TS
C. Technical Contact Information (☒ Mr. ☐ Mrs. ☐ Ms. ☐ Other:)_____
Name: Christopher G. Swanberg
Title: Executive Vice President, Environment, Health & Safety
Company Name: Element H2GEN, LLC
Mailing Address: 24 Greenway Plaza, Suite 405
City: Houston
State: TX
ZIP Code: 77046
Telephone No.: 281-352-1305
Fax No.:
Email Address: chris.swanberg@elementfuels.com
II. Facility and Site Information
A. Name and Type of Facility
Facility Name: Port of Brownsville Energy Complex
Type of Facility: ☒ Permanent ☐ Temporary

Form PI-1S
Registrations for Air Standard Permit
(Page 2)
Texas Commission on Environmental Quality

II. Facility and Site Information *(continued)*
For portable units, please provide the serial number of the equipment being authorized below.
Serial No(s):
B. Facility Location Information
Street Address: 17600 RL Ostos Road
If there is no street address, provide written driving directions to the site and provide the closest city or town, county, and ZIP code for the site (attach description if additional space is needed).
City: Brownsville
County: Cameron
ZIP Code: 78521
C. Core Data Form (**required** for Standard Permits 6006, 6007, and 6013).
Is the Core Data Form (TCEQ Form 10400) attached? ☒ Yes ☐ No
Customer Reference Number (CN):
Regulated Entity Number (RN):
D. TCEQ Account Identification Number (if known):
E. Type of Action
☒ Initial Application ☐ Change to Registration ☐ Renewal ☐ Renewal Certification
For Change to Registration, Renewal, or Renewal Certification actions provide the following:
Registration Number:
Expiration Date:
F. Standard Permit Claimed: 6005 - Electric Generating Unit
G. Previous Standard Exemption or PBR Registration Number:
Is this authorization for a change to an existing facility previously authorized under a standard exemption or PBR? ☐ Yes ☒ No
If "Yes," enter previous standard exemption number(s) and PBR registration number(s) and associated effective date in the spaces provided below.

II. Facility and Site Information *(continued)*
H. Other Facilities at this Site Authorized by Standard Exemption, PBR, or Standard Permit
Are there any other facilities at this site that are authorized by an Air Standard Exemption, PBR, or Standard Permit? ☐ Yes ☒ No
If "Yes," enter standard exemption number(s), PBR registration number(s), and Standard Permit registration number(s), and associated effective date in the spaces provided below.
Standard Exemption, PBR Registration, and Standard Permit Registration Number(s) and Effective Date(s)
I. Other Air Preconstruction Permits
Are there any other air preconstruction permits at this site? ☐ Yes ☒ No
If "Yes," enter permit number(s) in the spaces provided below.
J. Affected Air Preconstruction Permits
Does the standard permit directly affect any permitted facility? ☐ Yes ☒ No
If "Yes," enter permit number(s) in the spaces provided below.
K. Federal Operating Permit (FOP) Requirements
Is this facility located at a site that is required to obtain a FOP pursuant to 30 TAC Chapter 122? ☐ Yes ☒ No ☐ To Be Determined
Check the requirements of 30 TAC Chapter 122 that will be triggered if this standard permit is approved (*check all that apply).*
☐ Initial Application for a FOP ☐ Significant Revision for a SOP ☐ Minor Revision for a SOP
☐ Operational Flexibility/Off Permit Notification for a SOP ☐ Revision for a GOP
☐ To be Determined ☒ None
Identify the type(s) of FOP issued and/or FOP application(s) submitted/pending for the site. *(check all that apply)*
☐ SOP ☐ GOP ☐ GOP application/revision (submitted or under APD review) ☐ N/A
☐ SOP application/revision (submitted or under APD review)

Form PI-1S
Registrations for Air Standard Permit
(Page 4)
Texas Commission on Environmental Quality

III.	**Fee Information** ***(go to www.tceq.texas.gov/epay to pay online)***
A.	Fee Amount: 900.00
B.	Voucher number from ePay:
IV.	**Public Notice** *(if applicable)*
A.	Responsible Person (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Other:)_____
Name:	
Title:	
Company:	
Mailing Address:	
City:	
State:	
ZIP Code:	
Telephone No.:	
Fax No.:	
Email Address:	
B.	Technical Contact (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Other):_____
Name:	
Title:	
Company:	
Mailing Address:	
City:	
State:	
ZIP Code:	
Telephone No.:	
Fax No.:	
Email Address:	
C.	Bilingual Notice
Is a bilingual program required by the Texas Education Code in the School District?	☐ Yes ☐ No
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☐ Yes ☐ No

IV.	**Public Notice *(continued)*** *(if applicable) (continued)*	
If "Yes," list which language(s) are required by the bilingual program below?		
D.	Small Business Classification and Alternate Public Notice	
Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?		☐ Yes ☐ No
Is the site a major source under 30 TAC Chapter 122, Federal Operating Permit Program?		☐ Yes ☐ No
Are the site emissions of any individual regulated air contaminant equal to or greater than 50 tpy?		☐ Yes ☐ No
Are the site emissions of all regulated air contaminant combined equal to or greater than 75 tpy?		☐ Yes ☐ No
V.	**Renewal Certification Option**	
A.	Does the permitted facility emit an air contaminant on the Air Pollutant Watch List, and is the permitted facility located in an area on the watch list?	☐ Yes ☐ No
B.	For facilities participating in the Houston/Galveston/Brazoria area (HGB) cap and trade program for highly reactive VOCs (HRVOCs), do the HRVOCs need to be speciated on the maximum allowable emission rates table (MAERT)?	☐ Yes ☐ No
C.	Does the company and/or site have an unsatisfactory compliance history?	☐ Yes ☐ No
D.	Are there any applications currently under review for this standard permit registration?	☐ Yes ☐ No
E.	Are scheduled maintenance, startup, or shutdown emissions required to be included in the standard permit registration at this time?	☐ Yes ☐ No
F.	Are any of the following actions being requested at the time of renewal:	☐ Yes ☐ No
1.	Are there any facilities that have been permanently shutdown that are proposed to be removed from the standard permit registration?	☐ Yes ☐ No
2.	Do changes need to be made to the standard permit registration in order to remain in compliance?	☐ Yes ☐ No
3.	Are sources or facilities that have always been present and represented, but never identified in the standard permit registration, proposed to be included with this renewal?	☐ Yes ☐ No
4.	Are there any changes to the current emission rates table being proposed?	☐ Yes ☐ No
*Note: If answers to all of the questions in Section V. Renewal Certification Option are "No," use the certification option and skip to Section VII. of this form. If the answers to any of the questions in Section V. Renewal Certification Option are "Yes," the certification option **cannot** be used.*		
*If notice is applicable and comments are received in response to the public notice, the application does not qualify for the renewal certification option.		

VI. Technical Information Including State and Federal Regulatory Requirements		
Place a check next to the appropriate box to indicate what you have included in your submittal. *Note: Any technical or essential information needed to confirm that facilities are meeting the requirements of the standard permit must be provided. Not providing key information could result in an automatic deficiency and voiding of the project*.		
A. Standard Permit requirements (Checklists are optional; however, your review will go faster if you provide applicable checklists.)		
Did you demonstrate that the general requirements in 30 TAC Sections 116.610 and 116.615 are met?	☒ Yes	☐ No
Did you demonstrate that the individual requirements of the specific standard permit are met?	☒ Yes	☐ No
B. Confidential Information (All pages properly marked "CONFIDENTIAL").	☐ Yes	☒ No
C. Process Flow Diagram.	☒ Yes	☐ No
D. Process Description.	☒ Yes	☐ No
E. Maximum Emissions Data and Calculations.	☒ Yes	☐ No
F. Plot Plan.	☒ Yes	☐ No
G. Projected Start Of Construction Date, Start Of Operation Date, and Length of Time at Site:	☒ Yes	☐ No
Projected Start of Construction (provide date): 03/01/2025		
Projected Start of Operation (provide date): 05/01/2027		
Length of Time at the Site: permanent		
VII. Delinquent Fees and Penalties		
This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ are paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ website at: www.tceq.texas.gov/agency/financial/fees/delin/index.html.		

VIII. Signature Requirements
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7; the Texas Health and Safety Code, Chapter 382, the Texas Clean Air Act (TCAA) the air quality rules of the Texas Commission on Environmental Quality; or any local governmental ordinance or resolution enacted pursuant to the TCAA. I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name (printed): TOM RAMSEY
Signature (original signature required):
Date: 7/18/2024
IX. Copies of the Registration
The PI-1S application must be submitted through ePermits. No additional copies need to be sent to the Regional Office or local Air Pollution Control Program(s). The link to ePermits can be found here: www3.tceq.texas.gov/steers/.

Table 1(a) Emission Point Summary
Air Contaminant Data (Page 1)
Texas Commission on Environmental Quality

Date:	Permit No.:	Regulated Entity No.:	Area Name:	Customer Reference No.:
July 2024	TBD	TBD	Port of Brownsville Energy Complex	TBD

Review of application and issuance of permits will be expedited by supplying all necessary information requested on the Table.

EPN	FIN	Name	Component or Air Contaminant Name	Air Contaminant Emission Rate lb/hr	Air Contaminant Emission Rate TPY
T1	T1	Train 1	NOx	10.76	26.34
			NOx (MSS)	168.16	
			CO	13.10	25.52
			CO (MSS)	43.09	
			VOC	10.31	37.73
			PM	4.99	18.31
			PM_{10}	4.99	18.31
			$PM_{2.5}$	4.99	18.31
			SO_2	5.11	3.74
			NH_3	9.96	36.43
OIL1	OIL1	Turbine Oil Mist	VOC	<0.01	<0.01
			PM	<0.01	<0.01
			PM_{10}	<0.01	<0.01
			$PM_{2.5}$	<0.01	<0.01
T2	T2	Train 2	NOx	10.76	26.34
			NOx (MSS)	168.16	
			CO	13.10	25.52
			CO (MSS)	43.09	
			VOC	10.31	37.73
			PM	4.99	18.31
			PM_{10}	4.99	18.31
			$PM_{2.5}$	4.99	18.31
			SO_2	5.11	3.74
			NH_3	9.96	36.43

Table 1(a) Emission Point Summary
Air Contaminant Data (Page 1)
Texas Commission on Environmental Quality

Date:	Permit No.:	Regulated Entity No.:	Area Name:	Customer Reference No.:
July 2024	TBD	TBD	Port of Brownsville Energy Complex	TBD

Review of application and issuance of permits will be expedited by supplying all necessary information requested on the Table.

EPN	FIN	Name	Component or Air Contaminant Name	Air Contaminant Emission Rate lb/hr	Air Contaminant Emission Rate TPY
OIL2	OIL1	Turbine Oil Mist	VOC	<0.01	<0.01
			PM	<0.01	<0.01
			PM_{10}	<0.01	<0.01
			$PM_{2.5}$	<0.01	<0.01
FUG	FUG	Fugitive Emissions	VOC	0.01	0.05
			NH_3	0.01	0.04

EPN = Emission Point
FIN = Facility Identification Number

Table 1F
Air Quality Application Supplement
Texas Commission on Environmental Quality

Permit Number:	TBD
Application Submittal Date:	July 2024
Company:	Element H2GEN LLC
Regulated Entity Number:	**RN:** TBD
Named Source (Y/N):	☑ Yes ☐ No
City:	Brownsville
County:	Cameron
Permit Activity:	☑ New Source ☐ Modification

Complete for all Pollutants with a Project Emission Increase.

Questions	Ozone VOC	Ozone NO_x	CO	PM	PM_{10}	$PM_{2.5}$	SO_2	Other[1]
Is nonattainment potentially applicable? (Y/N)	No	No	No	No	No	No	No	
Is PSD potentially applicable? (Y/N)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	
Existing site PTE (tpy)? *	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Total project emissions increase (tpy from Table 2F)?	75.52	52.67	51.04	36.63	36.63	36.63	7.48	
Is the existing site a major source? (Y/N)	No	No	No	No	No	No	No	
If not, is the project a major source by itself? (Y/N)	No	No	No	No	No	No	No	
If site is major source, is the project increase significant? (Y/N)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
Net contemporaneous change, including proposed project, from Table 3F. (tpy)								
Major NSR Applicable? (Y/N)	No	No	No	No	No	No	No	

[1] Other pollutants. [Pb, H2S, TRS, H2SO4, Fluoride excluding HF, Greenhouse Gases as CO2e, etc.].

Table 2F
Project Emission Increase Supplement
Texas Commission on Environmental Quality

Pollutant[1]:	VOC
Permit Number:	TBD
Baseline Period (Month and Year):	n/a
To Baseline Period (Month and Year):	n/a

[1] Individual Table 2F's should be used to summarize the project emissions increase for each criteria pollutant using the EPA's "substantially related" test to determine the scope of the project.

New, Affected, or Modified Facilities[2]

Item Number	FIN	EPN	Permit Number	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Potential to Emit Emissions[5]	C Projected Actual Emissions[6]	Difference, (B-A) or (C-A)[7]	Correction[8]	Project Emissions Increases[9]
1.	T1	T1	TBD	-	-	37.73		37.73		37.73
2.	T2	T2	TBD	-	-	37.73		37.73		37.73
3.	OIL1	OIL1	TBD	-	-	<0.01		0.00		0.00
4.	OIL2	OIL2	TBD	-	-	<0.01		0.00		0.00
5.	FUG	FUG	TBD	-	-	0.05		0.05		0.05
6.										
7.										
8.										
9.										
10.										
								Total Project Emissions Increase		**75.52**

[2] Facility Identification Number (FIN) and Emission Point Number (EPN) as designated in NSR permit application or emission inventory.

[3] All records and calculations for these values must be available upon request.

[4] Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.

[5] Potential to Emit emissions are the current or proposed allowable emission rate. If Projected Actual Emissions are used for the source, they must be noted in the next column.

[6] Projected Actual Emissions are subject to 30 TAC 116.127 requirements and the basis for the projection identified in the Table 2F supplement.

[7] Proposed Potential to Emit (column B) or Projected Actual Emissions (Column C) minus Baseline Emissions (column A). New units must use Proposed Potential to Emit Emissions.

[8] Correction to be made to the Project Emission Increase for baseline actual emissions that could have accommodated or product demand growth during the baseline period, in accordance with 40 CFR 52.21(b)(41)(ii). Note, the could have accommodated or product demand growth correction may only be used with Projected Actual Emissions. The justification and basis for this estimate must be provided in the Table 2F supplement.

[9] Project Emissions Increase is obtained by subtracting the Correction column from the Difference column value. The number for each source may be positive or negative.

Table 2F
Project Emission Increase Supplement
Texas Commission on Environmental Quality

Pollutant[1]:	NOx
Permit Number:	TBD
Baseline Period (Month and Year):	n/a
To Baseline Period (Month and Year):	n/a

[1] Individual Table 2F's should be used to summarize the project emissions increase for each criteria pollutant using the EPA's "substantially related" test to determine the scope of the project.

New, Affected, or Modified Facilities[2]

Item Number	FIN	EPN	Permit Number	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Potential to Emit Emissions[5]	C Projected Actual Emissions[6]	Difference, (B-A) or (C-A)[7]	Correction[8]	Project Emissions Increases[9]
1.	T1	T1	TBD	-	-	26.34		26.34		26.34
2.	T2	T2	TBD	-	-	26.34		26.34		26.34
3.										
4.										
5.										
6.										
7.										
8.										
9.										
10.										
Total Project Emissions Increase										**52.67**

[2] Facility Identification Number (FIN) and Emission Point Number (EPN) as designated in NSR permit application or emission inventory.

[3] All records and calculations for these values must be available upon request.

[4] Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.

[5] Potential to Emit emissions are the current or proposed allowable emission rate. If Projected Actual Emissions are used for the source, they must be noted in the next column.

[6] Projected Actual Emissions are subject to 30 TAC 116.127 requirements and the basis for the projection identified in the Table 2F supplement.

[7] Proposed Potential to Emit (column B) or Projected Actual Emissions (Column C) minus Baseline Emissions (column A). New units must use Proposed Potential to Emit Emissions.

[8] Correction to be made to the Project Emission Increase for baseline actual emissions that could have accommodated or product demand growth during the baseline period, in accordance with 40 CFR 52.21(b)(41)(ii). Note, the could have accommodated or product demand growth correction may only be used with Projected Actual Emissions. The justification and basis for this estimate must be provided in the Table 2F supplement.

[9] Project Emissions Increase is obtained by subtracting the Correction column from the Difference column value. The number for each source may be positive or negative.

Table 2F
Project Emission Increase Supplement
Texas Commission on Environmental Quality

Pollutant[1]:	CO
Permit Number:	TBD
Baseline Period (Month and Year):	n/a
To Baseline Period (Month and Year):	n/a

[1] Individual Table 2F's should be used to summarize the project emissions increase for each criteria pollutant using the EPA's "substantially related" test to determine the scope of the project.

New, Affected, or Modified Facilities[2]

Item Number	FIN	EPN	Permit Number	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Potential to Emit Emissions[5]	C Projected Actual Emissions[6]	Difference, (B-A) or (C-A)[7]	Correction[8]	Project Emissions Increases[9]
1.	T1	T1	TBD	-	-	25.52		25.52		25.52
2.	T2	T2	TBD	-	-	25.52		25.52		25.52
3.										
4.										
5.										
6.										
7.										
8.										
9.										
10.										
Total Project Emissions Increase										**51.04**

[2] Facility Identification Number (FIN) and Emission Point Number (EPN) as designated in NSR permit application or emission inventory.

[3] All records and calculations for these values must be available upon request.

[4] Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.

[5] Potential to Emit emissions are the current or proposed allowable emission rate. If Projected Actual Emissions are used for the source, they must be noted in the next column.

[6] Projected Actual Emissions are subject to 30 TAC 116.127 requirements and the basis for the projection identified in the Table 2F supplement.

[7] Proposed Potential to Emit (column B) or Projected Actual Emissions (Column C) minus Baseline Emissions (column A). New units must use Proposed Potential to Emit Emissions.

[8] Correction to be made to the Project Emission Increase for baseline actual emissions that could have accommodated or product demand growth during the baseline period, in accordance with 40 CFR 52.21(b)(41)(ii). Note, the could have accommodated or product demand growth correction may only be used with Projected Actual Emissions. The justification and basis for this estimate must be provided in the Table 2F supplement.

[9] Project Emissions Increase is obtained by subtracting the Correction column from the Difference column value. The number for each source may be positive or negative.

Table 2F
Project Emission Increase Supplement
Texas Commission on Environmental Quality

Pollutant[1]:	PM/PM10/PM2.5
Permit Number:	TBD
Baseline Period (Month and Year):	n/a
To Baseline Period (Month and Year):	n/a

[1] Individual Table 2F's should be used to summarize the project emissions increase for each criteria pollutant using the EPA's "substantially related" test to determine the scope of the project.

New, Affected, or Modified Facilities[2]

Item Number	FIN	EPN	Permit Number	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Potential to Emit Emissions[5]	C Projected Actual Emissions[6]	Difference, (B-A) or (C-A)[7]	Correction[8]	Project Emissions Increases[9]
1.	T1	T1	TBD	-	-	18.31		18.31		18.31
2.	T2	T2	TBD	-	-	18.31		18.31		18.31
3.	OIL1	OIL1	TBD	-	-	<0.01		0.002		0.002
4.	OIL2	OIL2	TBD	-	-	<0.01		0.002		0.002
5.										
6.										
7.										
8.										
9.										
10.										
Total Project Emissions Increase										**36.63**

[2] Facility Identification Number (FIN) and Emission Point Number (EPN) as designated in NSR permit application or emission inventory.

[3] All records and calculations for these values must be available upon request.

[4] Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.

[5] Potential to Emit emissions are the current or proposed allowable emission rate. If Projected Actual Emissions are used for the source, they must be noted in the next column.

[6] Projected Actual Emissions are subject to 30 TAC 116.127 requirements and the basis for the projection identified in the Table 2F supplement.

[7] Proposed Potential to Emit (column B) or Projected Actual Emissions (Column C) minus Baseline Emissions (column A). New units must use Proposed Potential to Emit Emissions.

[8] Correction to be made to the Project Emission Increase for baseline actual emissions that could have accommodated or product demand growth during the baseline period, in accordance with 40 CFR 52.21(b)(41)(ii). Note, the could have accommodated or product demand growth correction may only be used with Projected Actual Emissions. The justification and basis for this estimate must be provided in the Table 2F supplement.

[9] Project Emissions Increase is obtained by subtracting the Correction column from the Difference column value. The number for each source may be positive or negative.

Table 2F
Project Emission Increase Supplement
Texas Commission on Environmental Quality

Pollutant[1]:	SO2
Permit Number:	TBD
Baseline Period (Month and Year):	n/a
To Baseline Period (Month and Year):	n/a

[1] Individual Table 2F's should be used to summarize the project emissions increase for each criteria pollutant using the EPA's "substantially related" test to determine the scope of the project.

New, Affected, or Modified Facilities[2]

Item Number	FIN	EPN	Permit Number	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Potential to Emit Emissions[5]	C Projected Actual Emissions[6]	Difference, (B-A) or (C-A)[7]	Correction[8]	Project Emissions Increases[9]
1.	T1	T1	TBD	-	-	3.74		3.74		3.74
2.	T2	T2	TBD	-	-	3.74		3.74		3.74
3.										
4.										
5.										
6.										
7.										
8.										
9.										
10.										
Total Project Emissions Increase										**7.48**

[2] Facility Identification Number (FIN) and Emission Point Number (EPN) as designated in NSR permit application or emission inventory.

[3] All records and calculations for these values must be available upon request.

[4] Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.

[5] Potential to Emit emissions are the current or proposed allowable emission rate. If Projected Actual Emissions are used for the source, they must be noted in the next column.

[6] Projected Actual Emissions are subject to 30 TAC 116.127 requirements and the basis for the projection identified in the Table 2F supplement.

[7] Proposed Potential to Emit (column B) or Projected Actual Emissions (Column C) minus Baseline Emissions (column A). New units must use Proposed Potential to Emit Emissions.

[8] Correction to be made to the Project Emission Increase for baseline actual emissions that could have accommodated or product demand growth during the baseline period, in accordance with 40 CFR 52.21(b)(41)(ii). Note, the could have accommodated or product demand growth correction may only be used with Projected Actual Emissions. The justification and basis for this estimate must be provided in the Table 2F supplement.

[9] Project Emissions Increase is obtained by subtracting the Correction column from the Difference column value. The number for each source may be positive or negative.

APPENDIX C. EGU STANDARD PERMIT

Air Quality Standard Permit for Electric Generating Units

Effective Date May 16, 2007

This standard permit authorizes electric generating units that generate electricity for use by the owner or operator and/or generate electricity to be sold to the electric grid, and that meet all of the conditions listed below.

(1) Applicability

(A) This standard permit may be used to authorize electric generating units installed or modified after the effective date of this standard permit and that meet the requirements of this standard permit.

(B) This standard permit may not be used to authorize boilers. Boilers may be authorized under the Air Quality Standard Permit for Boilers; 30 TAC § 106.183, Boilers, Heaters, and Other Combustion Devices; or a permit issued under the requirements of 30 TAC Chapter 116.

(2) Definitions

(A) East Texas Region - All counties traversed by or east of Interstate Highway 35 or Interstate Highway 37, including Bosque, Coryell, Hood, Parker, Somervell and Wise Counties.

(B) Installed - a generating unit is installed on the site when it begins generating electricity.

(C) West Texas Region - Includes all of the state not contained in the East Texas Region.

(D) Renewable fuel - fuel produced or derived from animal or plant products, byproducts or wastes, or other renewable biomass sources, excluding fossil fuels. Renewable fuels may include, but are not limited to, ethanol, biodiesel, and biogas fuels.

(3) Administrative Requirements

(A) Electric generating units shall be registered in accordance with 30 TAC § 116.611, Registration to Use a Standard Permit, using a current Form PI-1S. Units that meet the conditions of this standard permit do not have to meet 30 TAC § 116.610(a)(1), Applicability.

(B) Registration applications shall comply with 30 TAC § 116.614, Standard Permit Fees, for any single unit or multiple units at a site with a total generating capacity of 1 megawatt (MW) or greater. The fee for units or multiple units with a total generating capacity of less than 1 MW at a site shall

be $100.00. The fee shall be waived for units or multiple units with a total generating capacity of less than 1 MW at a site that have certified nitrogen oxides (NO_x) emissions that are less than 10 percent of the standards required by this standard permit.

(C) No owner or operator of an electric generating unit shall begin construction and/or operation without first obtaining written approval from the executive director.

(D) Records shall be maintained and provided upon request to the Texas Commission on Environmental Quality (TCEQ) for the following:

(i) Hours of operation of the unit;

(ii) Maintenance records, maintenance schedules, and/or testing reports for the unit to document re-certification of emission rates as required by subsection (4)(G) below; and

(iii) Records to document compliance with the fuel sulfur limits in subsection (4)(C).

(E) Electric generators powered by gas turbines must meet the applicable conditions, including testing and performance standards, of Title 40 Code of Federal Regulations (CFR) Part 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, and applicable requirements of 40 CFR Part 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.

(F) Compliance with this standard permit does not exempt the owner or operator from complying with any applicable requirements of 30 TAC Chapter 117, Control of Air Pollution from Nitrogen Compounds, or 30 TAC Chapter 114, Control of Air Pollution from Motor Vehicles.

(4) General Requirements

(A) Emissions of NO_x from the electric generating unit shall be certified by the manufacturer or by the owner or operator in pounds of pollutant per megawatt hour (lb/MWh). This certification must be displayed on the name plate of the unit or on a label attached to the unit. Test results from U.S. Environmental Protection Agency (EPA) reference methods, California Air Resources Board methods, or equivalent alternative testing methods approved by the executive director used to verify this certification shall be provided upon request to the TCEQ. The unit must operate on the same fuel(s) for which the unit was certified.

(B) Electric generating units that use combined heat and power (CHP) may take

credit for the heat recovered from the exhaust of the combustion unit to meet the emission standards in subsections (4)(D), (4)(E), and (4)(F). Credit shall be at the rate of one MWh for each 3.4 million British Thermal Units of heat recovered. The following requirements must be met to take credit for CHP for units not sold and certified as an integrated package by the manufacturer:

(i) The owner or operator must provide as part of the application documentation of the heat recovered, electric output, efficiency of the generator alone, efficiency of the generator including CHP, and the use for the non-electric output, and

(ii) The heat recovered must equal at least 20 percent of the total energy output of the CHP unit.

(C) Fuels combusted in these electric generating units are limited to:

(i) Natural gas containing no more than ten grains total sulfur per 100 dry standard cubic feet;

(ii) Landfill gas, digester gas, stranded oilfield gas, or gaseous renewable fuel containing no more than 30 grains total sulfur per 100 dry standard cubic feet; or

(iii) Liquid fuels (including liquid renewable fuel) not containing waste oils or solvents and containing less than 0.05 percent by weight sulfur.

(D) Except as provided in subsections (4)(F) and (4)(H), NO_x emissions for units 10 MW or less shall meet the following limitations based upon the date the unit is installed and the region in which it operates:

East Texas Region:

(i) Units installed prior to January 1, 2005 and

(a) operating more than 300 hours per year - 0.47 lb/MWh;

(b) operating 300 hours or less per year - 1.65 lb/MWh;

(ii) Units installed on or after January 1, 2005 and

(a) operating more than 300 hours per year, with a capacity greater than 250 kilowatts (kW) - 0.14 lb/MWh;

(b) operating 300 hours or less per year - 0.47 lb/MWh; or

(c) any unit with a capacity of 250 kW or less - 0.47 lb/MWh.

West Texas Region:

(i) Units operating more than 300 hours per year - 3.11 lb/MWh;

(ii) Units operating 300 hours or less per year - 21 lb/MWh. Units certified to comply with applicable Tier 1, 2, or 3 emission standards in 40 CFR Part 89, Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines, are deemed to satisfy this emission limit.

(E) Except as provided in subsections (4)(F) and (4)(H), NO_x emissions for units greater than 10 MW shall meet the following limitations:

(i) Units operating more than 300 hours per year - 0.14 lb/MWh;

(ii) Units operating 300 hours or less per year - 0.38 lb/MWh.

(F) Electric generating units firing any gaseous or liquid fuel that is at least 75 percent landfill gas, digester gas, stranded oil field gas, or renewable fuel content by volume, shall meet a NO_x emission limit of 1.90 lb/MWh. Units in West Texas with a capacity of 10 MW or less that fire at least 75 percent landfill gas, digester gas, stranded oilfield gases, or gaseous or liquid renewable fuel by volume, must comply with the applicable West Texas NO_x limit in subsection (4)(D).

(G) To ensure continuing compliance with the emissions limitations, the owner or operator shall re-certify a unit every 16,000 hours of operation, but no less frequently than every three years. Re-certification may be accomplished by following a maintenance schedule that the manufacturer certifies will ensure continued compliance with the required NO_x standard or by third party testing of the unit using appropriate EPA reference methods, California Air Resources Board methods, or equivalent alternative testing methods approved by the executive director to demonstrate that the unit still meets the required emission standards. After re-certification, the unit must operate on the same fuel(s) for which the unit was re-certified.

(H) The NO_x emission limits in subsections (4)(D)-(4)(F) are subject to the following exceptions:

(i) The hourly NO_x emission limits do not apply at times when the ambient air temperature at the location of the unit is less than 0 degrees Fahrenheit.

(ii) At times when a unit is operating at less than 80% of rated load, an alternative NO_x emission standard for that unit may be determined by multiplying the applicable emission standard in subsections (4)(D)-(4)(F) by the rated load of the EGU (in MW), to produce an allowable hourly

mass NO_x emission rate. In order to use this alternative standard, an owner or operator must maintain records that demonstrate compliance with the alternative emission standard, and make such records available to the TCEQ or any local air pollution control agency with jurisdiction upon request.