TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

CONSOLIDATED *AMENDED* NOTICE OF RECEIPT OF APPLICATION AND INTENT TO OBTAIN PERMIT AND NOTICE OF APPLICATION AND PRELIMINARY DECISION

AIR QUALITY PERMIT NUMBERS 1504A, PSDTX748M2, AND N148M3

APPLICATION AND PRELIMINARY DECISION. Chevron Phillips Chemical Company LP, 9500 Interstate 10 East, Baytown, TX 77521-8155, has applied to the Texas Commission on Environmental Quality (TCEQ) for an amendment to State Air Quality Permit 1504A, modification to Prevention of Significant Deterioration (PSD) Air Quality Permit PSDTX748M2, and modification to Nonattainment Permit Number N148M3, which would authorize modification to the Ethylene Production Plant located at 9500 Interstate 10 East, Baytown, Harris County, Texas 77521. The existing facility will emit the following air contaminants in a significant amount to require a Nonattainment Review: volatile organic compounds and nitrogen oxides. The facility will emit the following air contaminants in a significant amount: carbon monoxide, nitrogen oxides and organic compounds. In addition, the facility will emit: hazardous air pollutants, hydrogen sulfide, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less and sulfur dioxide. The facility will also emit greenhouse gases.

A full PSD increment analysis was not required because the predicted impacts of all regulated pollutants subject to PSD increment review were below the significant impact level for each pollutant.

This application was submitted to the TCEQ on December 3, 2024. The executive director has determined that the emissions of air contaminants from the existing facility which are subject to PSD review will not violate any state or federal air quality regulations and will not have any significant adverse impact on soils, vegetation, or visibility. All air contaminants have been evaluated, and “best available control technology” will be used for the control of these contaminants.

Harris County has been designated nonattainment for ozone because Continuous Ambient Air Monitoring Stations have shown that ambient concentrations of ozone exceed the National Ambient Air Quality Standards (NAAQS) for ozone. Ground-level ozone is not emitted directly into the air, but is created by chemical reactions between nitrogen oxides (NO_X) and volatile organic compounds (VOC). The Federal Clean Air Act (FCAA) requires that new major stationary sources and major modifications at sources in designated nonattainment areas must satisfy nonattainment new source review prior to commencement of construction.

As required by the nonattainment review, all air contaminants have been evaluated and the “lowest achievable emission rate” has been addressed for the control of these contaminants. The emission increases from this project will be offset with emission reductions by a ratio of 1.3 to 1. Furthermore, the applicant has demonstrated that the benefits of the existing facility significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification. Finally, the applicant has certified that all major stationary sources owned or operated by the applicant in the state are in compliance or on a schedule for compliance with all applicable state and federal emission limitations and standards. The executive director, therefore, has made the preliminary determination to issue this permit.

The executive director has completed the technical review of the application and prepared a draft permit which, if approved, would establish the conditions under which the facility must operate. The permit application, executive director’s preliminary decision, draft permit, and the executive director’s preliminary determination summary and executive director’s air quality analysis, will be available for viewing and copying at the TCEQ central office, the TCEQ Houston regional office, and the Sterling Municipal Library, 1 Mary Wilbanks Avenue, Baytown, Harris County, Texas beginning the first day of publication of this notice. The facility’s compliance file, if any exists, is available for public review at the TCEQ

Houston Regional Office, 5425 Polk Street, Suite H, Houston, Texas. The application, including any updates, is available electronically at the following webpage: https://www.tceq.texas.gov/permitting/air/airpermit-applications-notices.

INFORMATION AVAILABLE ONLINE. These documents are accessible through the Commission's Web site at www.tceq.texas.gov/goto/cid: the executive director's preliminary decision which includes the draft permit, the executive director's preliminary determination summary, air quality analysis, and, once available, the executive director's response to comments and the final decision on this application. Access the Commissioners' Integrated Database (CID) using the above link and enter the permit number for this application. The public location mentioned above, the Sterling Municipal Library, provides public access to the internet. This link to an electronic map of the site or facility's general location is provided as a public courtesy and not part of the application or notice. For exact location, refer to application. https://gisweb.tceq.texas.gov/LocationMapper/?marker=-94.933888,29.8175&level=13.

PUBLIC COMMENT/PUBLIC MEETING. You may submit public comments or request a public meeting to the Office of the Chief Clerk at the address below. The purpose of a public meeting is to provide the opportunity to submit comment or to ask questions about the application. The TCEQ will hold a public meeting if the executive director determines that there is a significant degree of public interest in the application, if requested by an interested person, or if requested by a local legislator. A public meeting is not a contested case hearing. **You may submit additional written public comments within 30 days of the date of newspaper publication of this notice in the manner set forth in the AGENCY CONTACTS AND INFORMATION paragraph below.**

After the deadline for public comment, the executive director will consider the comments and prepare a response to all relevant and material or significant public comment. **The response to comments, along with the executive director's decision on the application, will be mailed to everyone who submitted public comments or is on a mailing list for this application. The mailing will also provide instructions for requesting a contested case hearing or reconsideration of the executive director's decision.**

OPPORTUNITY FOR A CONTESTED CASE HEARING. You may request a contested case hearing regarding the portions of the application for State Air Quality Permit Number 1504A, PSD Air Quality Permit Number PSDTX748M2, and for Nonattainment Air Quality Permit Number N148M3. A contested case hearing is a legal proceeding similar to a civil trial in a state district court. A person who may be affected by emissions of air contaminants from the facility is entitled to request a hearing. A contested case hearing request must include the following: (1) your name (or for a group or association, an official representative), mailing address, daytime phone number; (2) applicant's name and permit number; (3) the statement "I/we request a contested case hearing;" (4) a specific description of how you would be adversely affected by the application and air emissions from the facility in a way not common to the general public; (5) the location and distance of your property relative to the facility; (6) a description of how you use the property which may be impacted by the facility; and (7) a list of all disputed issues of fact that you submit during the comment period. If the request is made by a group or association, one or more members who have standing to request a hearing must be identified by name and physical address. The interests the group or association seeks to protect must also be identified. You may also submit your proposed adjustments to the application/permit which would satisfy your concerns. Requests for a contested case hearing must be submitted in writing within 30 days following this notice to the Office of the Chief Clerk, at the address provided in the information section below.

A contested case hearing will only be granted based on disputed issues of fact or mixed questions of fact and law that are relevant and material to the Commission's decisions on the application. The Commission may only grant a request for a contested case hearing on issues the requestor submitted in their timely comments that were not subsequently withdrawn. Issues that are not submitted in public comments may not be considered during a hearing.

EXECUTIVE DIRECTOR ACTION. If a timely contested case hearing request is not received or if all timely contested case hearing requests are withdrawn regarding State Air Quality Permit Number 1504A, PSD Air Quality Permit Number PSDTX748M2, and for Nonattainment Air Quality Permit Number N148M3, the executive director may issue final approval of the application. The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application, and will be posted electronically to the CID. If any timely hearing requests are received and not withdrawn, the executive director will not issue final approval of the State Air Quality Permit Number 1504A, PSD Air Quality Permit Number PSDTX748M2, and for Nonattainment Air Quality Permit Number N148M3 and will forward the application and requests to the Commissioners for their consideration at a scheduled commission meeting.

MAILING LIST. You may ask to be placed on a mailing list to obtain additional information on this application by sending a request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION. Public comments and requests must be submitted either electronically at www.tceq.texas.gov/goto/comment, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC 105, P.O. Box 13087, Austin, Texas 78711-3087. Please be aware that any contact information you provide, including your name, phone number, email address and physical address will become part of the agency's public record. For more information about the permitting process, please call the TCEQ Public Education Program, Toll Free, at 1-800-687-4040 or visit their website at www.tceq.texas.gov/goto/pep. Si desea información en Español, puede llamar al 1-800-687-4040. You can also view our website for public participation opportunities at www.tceq.texas.gov/goto/participation.

Further information may also be obtained from Chevron Phillips Chemical Company LP at the address stated above or by calling Ms. Julie Hicks, Environmental Superintendent at (281) 421-6331.

Notice Issuance Date: March 16, 2026

COMISIÓN DE CALIDAD AMBIENTAL DE TEXAS

EJEMPLO A

AVISO CONSOLIDADO Y ENMENDADO DE RECEPCIÓN DE SOLICITUD E INTENCIÓN DE OBTENER PERMISO Y AVISO DE SOLICITUD Y DECISIÓN PRELIMINAR

NÚMEROS DE PERMISO DE CALIDAD DEL AIRE 1504A, PSDTX748M2 Y N148M3

SOLICITUD Y DECISIÓN PRELIMINAR. Chevron Phillips Chemical Company LP, 9500 Interstate 10 East, Baytown, TX 77521-8155, ha solicitado a la Comisión de Calidad Ambiental de Texas (TCEQ, por sus siglas en inglés) enmienda al Permiso Estatal de Calidad del Aire 1504A, modificación al Permiso de Calidad del Aire de Prevención de Deterioro Significativo (PSD) PSDTX748M2, y modificación al Permiso de No Cumplimiento Número N148M3, que autorizaría la modificación de la Planta de Producción de Etileno ubicada en 9500 Interstate 10 East, Baytown, Condado de Harris, Texas 77521. La instalación existente emitirá los siguientes contaminantes del aire en una cantidad significativa que requerirá una Revisión de Incumplimiento: compuestos orgánicos volátiles y óxidos de nitrógeno. La instalación emitirá los siguientes contaminantes del aire en una cantidad significativa: monóxido de carbono, óxidos de nitrógeno y compuestos orgánicos. Además, la instalación emitirá: contaminantes atmosféricos peligrosos, sulfuro de hidrógeno, materia particulada incluyendo materia particulada con diámetros de 10 micrones o menos y de 2,5 micrones o menos, y dióxido de azufre. La instalación también emitirá gases de efecto invernadero.

No se requirió un análisis completo del incremento de PSD porque los impactos previstos de todos los contaminantes regulados sujetos a la revisión del incremento de PSD estaban por debajo del nivel de impacto significativo para cada contaminante.

Esta solicitud fue presentada a la TCEQ el 3 de diciembre de 2024. El director ejecutivo ha determinado que las emisiones de contaminantes del aire provenientes de la instalación existente, que están sujetas a la revisión PSD, no violarán ninguna normativa estatal o federal de calidad del aire y no tendrán ningún impacto adverso significativo en los suelos, la vegetación o la visibilidad. Todos los contaminantes del aire han sido evaluados y se utilizará la "mejor tecnología de control disponible" para el control de estos contaminantes.

El Condado de Harris ha sido designado como área de no cumplimiento para el ozono porque las Estaciones Continuas de Monitoreo de Aire Ambiental han mostrado que las concentraciones ambientales de ozono exceden los Estándares Nacionales de Calidad del Aire Ambiental (NAAQS) para el ozono. El ozono a nivel del suelo no se emite directamente al aire, sino que se crea mediante reacciones químicas entre óxidos de nitrógeno (NOX) y compuestos orgánicos volátiles (COV). La Ley Federal de Aire Limpio (FCAA) requiere que las nuevas fuentes estacionarias mayores y las modificaciones importantes en fuentes ubicadas en áreas designadas de no cumplimiento deben cumplir con la revisión de nuevas fuentes en áreas de no cumplimiento antes del inicio de la construcción.

Como lo requiere la revisión de incumplimiento, se han evaluado todos los contaminantes del aire y se ha abordado la “tasa de emisión más baja alcanzable” para el control de estos contaminantes. Los aumentos de emisiones de este proyecto se compensarán con reducciones de emisiones en una proporción de 1.3 a 1. Además, el solicitante ha demostrado que los beneficios de la instalación existente superan significativamente los costos ambientales y sociales impuestos como resultado de su ubicación, construcción o modificación. Finalmente, el solicitante ha certificado que todas las fuentes estacionarias importantes que posee o opera en el estado cumplen o están en un programa de cumplimiento con todas las limitaciones y normas de emisión estatales y federales aplicables. Por lo tanto, el director ejecutivo ha tomado la determinación preliminar de emitir este permiso.

El director ejecutivo ha completado la revisión técnica de la solicitud y ha preparado un proyecto de permiso que, de ser aprobado, establecería las condiciones en las que la instalación debe operar. La solicitud de permiso, la decisión preliminar del director ejecutivo, el borrador del permiso, y el resumen de la determinación preliminar del director ejecutivo y el análisis de calidad del aire del director ejecutivo, estarán disponibles para su consulta y copia en la oficina central de la TCEQ, la oficina regional de la TCEQ en Houston y la Biblioteca Municipal de Sterling, 1 Mary Wilbanks Avenue, Baytown, Condado de Harris, Texas a partir del primer día de publicación de este aviso. El expediente de cumplimiento de la instalación, si existe, está disponible para su revisión pública en la Oficina Regional de TCEQ en Houston, 5425 Polk Street, Suite H, Houston, Texas. La solicitud, incluyendo cualquier actualización, está disponible electrónicamente en la siguiente página web: https://www.tceq.texas.gov/permitting/air/airpermit-applications-notices.

INFORMACIÓN DISPONIBLE EN LÍNEA. Estos documentos son accesibles a través del sitio web de la Comisión en **www.tceq.texas.gov/goto/cid:** la decisión preliminar del director ejecutivo que incluye el borrador del permiso, el resumen de la determinación preliminar del director ejecutivo, el análisis de calidad del aire y, una vez disponible, la respuesta del director ejecutivo a los comentarios y la decisión final sobre esta solicitud. Acceda a la Base de Datos Integrada de los Comisionados (CID) usando el enlace anterior e ingrese el número de permiso para esta solicitud. La ubicación pública mencionada arriba, la Biblioteca Municipal de Sterling, proporciona acceso público a internet. Este enlace a un mapa electrónico de la ubicación general del sitio o instalación se proporciona como una cortesía pública y no forma parte de la solicitud o aviso. Para conocer la ubicación exacta, consulte la solicitud. **https://gisweb.tceq.texas.gov/LocationMapper/?marker=-94.933888,29.8175&level=13.**

COMENTARIO PÚBLICO/REUNIÓN PÚBLICA. Puede enviar comentarios públicos o solicitar una reunión pública a la Oficina del Secretario Principal en la dirección que se indica a continuación. El propósito de una reunión pública es para brindar la oportunidad de enviar comentarios o hacer preguntas sobre la solicitud. La TCEQ convocará una reunión pública si el director ejecutivo determina que existe un grado significativo de interés público en la solicitud, si lo solicita una persona interesada, o si lo solicita un legislador local. Una reunión pública no es una audiencia de caso impugnado. **Puede enviar comentarios públicos adicionales por escrito dentro de los 30 días posteriores a la fecha de publicación de este aviso en el periódico de la manera establecida en el párrafo CONTACTOS E INFORMACIÓN DE LA AGENCIA a continuación.**

Después de la fecha límite para comentarios públicos, el director ejecutivo considerará los comentarios y preparará una respuesta a todos los comentarios públicos relevantes y materiales o significativos**. La respuesta a los comentarios, junto con la decisión del director ejecutivo sobre la solicitud, se enviará por correo a todos los que hayan presentado comentarios públicos o estén en una lista de correo para esta solicitud. El envío por correo también proporcionará instrucciones para solicitar una audiencia de caso impugnado o la reconsideración de la decisión del director ejecutivo.**

OPORTUNIDAD PARA UNA AUDIENCIA DE CASO IMPUGNADO. Usted puede solicitar una audiencia de caso impugnado respecto a las partes de la solicitud del Permiso Estatal de Calidad del Aire Número 1504A, Permiso de Calidad del Aire PSD Número PSDTX748M2, y del Permiso de Calidad del Aire por No Cumplimiento Número N148M3. Una audiencia de caso impugnado es un procedimiento legal similar a un juicio civil en un tribunal de distrito estatal. Una persona que pueda verse afectada por las emisiones de contaminantes del aire provenientes de la instalación tiene derecho a solicitar una audiencia. La solicitud de una audiencia en un caso impugnado debe incluir lo siguiente: (1) su nombre (o, en el caso de un grupo o asociación, un representante oficial), dirección postal, número de teléfono durante el día; (2) nombre del solicitante y número de permiso; (3) la declaración "Yo/nosotros solicitamos una audiencia de caso impugnado;" (4) una descripción específica de cómo se vería afectado negativamente por la solicitud y las emisiones de aire de la instalación de una manera no común al público en general; (5) la ubicación y la distancia de su propiedad en relación con la instalación; (6) una descripción de cómo utiliza la propiedad que podría verse afectada por la instalación; y (7) una lista de todos los asuntos de hecho disputados que usted presente durante el período de comentarios. Si la solicitud es realizada por un grupo o asociación, se debe identificar por nombre y domicilio físico a uno o más miembros que tengan legitimación para solicitar una audiencia. También se deben identificar los intereses que el grupo o la asociación buscan proteger. Además, puede enviar sus ajustes propuestos a la solicitud/permiso que satisfagan sus preocupaciones. Las solicitudes para una audiencia de caso impugnado deben presentarse por escrito dentro de los 30 días siguientes a este aviso en la Oficina del Secretario Principal, en la dirección proporcionada en la sección de información a continuación.

Una audiencia de caso impugnado solo se concederá en base a cuestiones de hecho disputadas o preguntas mixtas de hecho y derecho que sean relevantes y materiales para las decisiones de la Comisión sobre la solicitud. La Comisión solo podrá conceder una solicitud de audiencia de caso impugnado sobre cuestiones que el solicitante haya presentado en sus comentarios oportunos y que no hayan sido posteriormente retirados. No se podrán considerar durante una audiencia las cuestiones que no se hayan presentado en los comentarios públicos.

ACCIÓN DEL DIRECTOR EJECUTIVO. Si no se recibe una solicitud de audiencia de caso impugnado dentro del plazo establecido o si todas las solicitudes de audiencia de caso impugnado presentadas a tiempo se retiran con respecto al Permiso de Calidad del Aire del Estado Número 1504A, Permiso de Calidad del Aire PSD Número PSDTX748M2, y para el Permiso de Calidad del Aire de No Conformidad Número N148M3, el director ejecutivo puede emitir la aprobación final de la solicitud. La respuesta a los comentarios, junto con la decisión del director ejecutivo sobre la solicitud, se enviará por correo a todos los que hayan presentado comentarios públicos o estén en una lista de correo para esta solicitud, y se publicará electrónicamente en el CID. Si se reciben solicitudes de audiencia oportunas y no se retiran, el director ejecutivo no emitirá la aprobación final del Permiso Estatal de Calidad del Aire Número 1504A, del Permiso PSD de Calidad del Aire Número PSDTX748M2, ni del Permiso de Calidad del Aire para Áreas en Incumplimiento Número N148M3, y remitirá la solicitud y las solicitudes a los Comisionados para su consideración en una reunión programada de la comisión.

LISTA DE CORREO. Puede solicitar ser colocado en una lista de correo para obtener información adicional sobre esta solicitud enviando una solicitud a la Oficina del Secretario Oficial a la dirección a continuación.

CONTACTOS E INFORMACIÓN DE LA AGENCIA. Los comentarios y solicitudes públicas deben enviarse electrónicamente a www.tceq.texas.gov/goto/comment, o por escrito a la Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. Favor de tener presente que cualquier información de contacto que proporcione (nombre, teléfono, dirección de correo electrónico y dirección física inclusive) será parte de los registros públicos de la agencia. Para más información sobre el proceso de tramitación de permisos, favor de llamar al Programa de Educación pública de la TCEQ sin costo al 1-800-687-4040, o bien visitar su sitio web, www.tceq.texas.gov/goto/pep. Para información en español, favor de llamar al 1-800-687-4040. También es posible consultar oportunidades de participación pública en nuestro sitio web, www.tceq.texas.gov/goto/participation.

También se puede obtener más información de Chevron Phillips Chemical Company LP en la dirección indicada anteriormente o llamando a Ms. Julie Hicks, Superintendente Ambiental at (281) 421-6331.

Fecha de Emisión del Aviso: 16 de marzo de 2026

Special Conditions

Permit Numbers 1504A, PSDTX748M2, and N148M3

1. This permit authorizes Chevron Philips Chemical Company's Cedar Bayou Facility, a petrochemical processing facility located at Baytown, Harris County, Texas.

   This permit authorizes emissions only from those points listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates" (MAERT), and the facilities covered by this permit are authorized to emit subject to the emission rate limits on that table and other operating conditions specified in this permit. The annual rates are based on any consecutive 12-month period unless otherwise noted.

2. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing volatile organic compounds (VOC) at a concentration of greater than 1 percent are not authorized by this permit unless authorized on the MAERT. Any releases directly to atmosphere from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration greater than 1 weight percent are not consistent with good practice for minimizing emissions, with the exception of the equipment listed below:

   A. Process Safety Valves, Nos. C4016A and C4016B, from the ethylene stripper;

   B. Two Process Safety Valves, Nos. C313 and C314, from the demethanizer;

   C. Rupture Disk, No. PSE 4027, located on the acetylene product pipeline;

   D. Rupture Disk, No. PSE 4032, located on acetylene flare drum;

   E. Rupture Disk, No. PSE 4067, located on the acetylene/fuel gas discharge flame arrestor vessel FA-467;

   F. Rupture Disks, Nos. PSE 4068A and 4068B, located on the acetylene compressor discharge separator vessels FA-463A and FA-463B;

   G. Rupture Disk, No. PSE 4079, located on the Acetylene Fuel Gas Flame Arrestor Vessel FA-468; and

   H. Rupture Disk, No. PSE 4042, located on the existing acetylene flare flame arrestor vessel FA-456.

   I. Atmospheric valves on EU 1594 low pressure closed vent system.

Federal Applicability

3. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources promulgated in Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

   A. Subpart A, General Provisions

   B. Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

   C. Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984

D. Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

E. Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

4. These facilities shall comply with all applicable requirements of the U.S. EPA regulations on National Emission Standards for Hazardous Air Pollutants in 40 CFR Part 61:

   A. Subpart A, General Provisions

   B. Subpart FF, National Emission Standard for Benzene Waste Operations

5. These facilities shall comply with all applicable requirements of the U.S. EPA regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63:

   A. Subpart A, General Provisions

   B. Subpart SS, National Emission Standards for Closed Vent Systems, Control Devices, Recovery Devices and Routing to a Fuel Gas System or a Process

   C. Subpart UU, National Emission Standards for Equipment Leaks – Control Level 2 Standards

   D. Subpart WW, National Emission Standards for Storage Vessels (Tanks) – Control Level 2

   E. Subpart XX, National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations

   F. Subpart YY, National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards

   G. Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines **(6/20)**

   H. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boiler and Process Heaters **(6/20)**

Emission Banking and Trading

6. This Nonattainment New Source Review (NNSR) permit is issued based on the requirement that the permit holder offset the project emission increase for facilities authorized by this permit prior to the commencement of operation, through participation in the TCEQ Emission Banking and Trading (EBT) Program in accordance with the rules in 30 TAC Chapter 101, Subchapter H.

7. The permit holder shall use 311.6 tons per year (tpy) of VOC emission reduction credits (ERC) to offset the 239.68 tpy VOC project emission increase for the facilities authorized by this permit at a ratio of 1.3 to 1.0. **(TBD)**

   A. The permit holder shall use 247.8 tons per year (tpy) of VOC emission reduction credits (ERCs) from TCEQ certificate numbers 2583, 3206, 3253, 3453, 3505, 3506, 3514, 4314, 4352, 4397, 4353, 4351, 4459, 4460, 4461, 4462, 4463, 4464, 4465, 4466, 4467, 4468, 4469, and 4470 to offset a portion of the VOC project emission increase for facilities authorized by this permit at a ratio of 1.3:1.

B. In addition to, or in place of using credits as described in Special Condition 7.A., the permit holder may use up to 63.8 tpy of Highly Reactive Volatile Organic Compounds Emission Cap and Trade (HECT) allowances to offset the 63.8 tpy VOC project emission increase from the following HECT applicable facilities: flare (EPN PK-905) and cooling tower (EPN PK-840) authorized by this permit at a ratio of 1:1.

8. The permit holder shall use 354.5 tpy of NO_x emission reduction credits to offset the 272.66 tpy NO_x project emission increase for the facilities authorized by this permit at a ratio of 1.3 to 1.0. **(TBD)**

A. The permit holder shall use 118.9 tons per year (tpy) of NOx emission reduction credits (ERCs) from TCEQ certificate numbers 2581, 2634, 3150 3154, 3437, 3438, 3439, 3441, 3501, 3502, 3503, 3504, 3507, 3508, 3509, 4312, 4319, 4320, 4321, 4393, 4394, 4395, 4396, 4409, 4410, 4411, 4412, 4413, and 4471to offset a portion of NOx project emission increase for facilities authorized by this permit at a ratio of 1.3:1.

B. In addition to, or in place of, using credits as described in Special Condition 8.A., the permit holder may use up to 235.6 tpy of Mass Emission Cap and Trade (MECT) allowances to offset the 188.40 tpy NOx project emission increase for the following MECT applicable facilities: cracking furnaces (EPNs H-101, H-102, H-103, H-104, H-105, H-106, H-107, H-108) and HP Boiler (EPN PK-830). An amount up to 188.4 tpy may be used to satisfy the authorized ratio of 1:1 with an additional 47.20 tpy to satisfy a portion of the ratio of 0.3:1.

Offsets – 2020 Flare Amendment (TCEQ Project No. 320798)

9. This Nonattainment (NNSR) permit is issued/approved based on the requirement that the permit holder offset the project emission increase for facilities authorized by NSR Permit Nos. 1504A, 2462C, 37063, 19027, and 46305 prior to the commencement of operation, through participation in the TCEQ Emission Banking and Trading (EBT) Program in accordance with the rules in 30 TAC Chapter 101, Subchapter H.

A. The permit holder shall use 20.0 tpy of NOx credits to offset the 16.60 tpy NOx project emission increase for the facilities authorized by this permit at a ratio of 1.2 to 1.0

B. The permit holder shall use 15.0 tons per year (tpy) of NOx emission reduction credits (ERCs) from TCEQ Certificate No. 3667, 4.1 tons per year from TCEQ Certificate No. 3668, and 0.9 tons per year from TCEQ Certificate No. 3720 to offset the NOx project emission increase for facilities authorized by TCEQ NSR Project No. 320798. **(06/22)**

Emission Standards, Fuel Specifications, and Operational Limitations

10. Emissions from the following combustion devices shall not exceed the following: **(03/21)**

A. Except where provided otherwise in subparagraph D of this Special Condition, emissions from the following combustion devices shall not exceed the following:

Facility ID(s)	EPN(s)	Pollutant	Standard	Averaging Period
Cracking Furnace BA-101 through BA-113	BA-101 through BA-113	NO_X	0.025 lbs/MMBtu	rolling 12-months
		NH_3	10 ppmv @ 3% O_2 (dry basis)	24-hrs (if equipped with NH_3 CEMS) 1-hr block (if not equipped with NH3 CEMS)
Cracking Furnace BA-117	BA-117	NO_X	0.06 lbs/MMBtu	rolling 12-months
Boilers BF-801A, BF-801B, & BF-801C	1592-10 & 1592-11	NO_X	0.084 lbs/MMBtu	rolling 12-months
Boiler PK-830	PK-830	NO_X	0.01 lbs/MMBtu	rolling 12-months
		NO_X	0.025 lbs/MMBtu	1-hr routine operation
		NH_3	10 ppmv @ 3% O_2 (dry basis)	24-hrs (if equipped with NH_3 CEMS) 1-hr block (if not equipped with NH3 CEMS)
Cracking Furnace H-101 through H-108	H-101 through H-108	NO_x	0.025 lbs/MMBtu	1-hr routine operation
		CO	50 ppmvd @ 3% O_2	rolling 12-months
Cracking Furnace H-109	H-109	NO_x	0.015 lbs/MMBtu	1-hr routine operation
		CO	50 ppmvd @ 3% O_2	rolling 12 months
Cracking Furnace H-101 through H-109	H-101 through H-109	NO_x	0.01 lbs/MMBtu	rolling 12-months
		NH_3	10 ppmv @ 3% O_2 (dry basis)	24-hrs (if equipped with NH_3 CEMS) 1-hr block (if not equipped with NH3 CEMS)

B. Compliance with the NOx and CO emission standards of subparagraph A shall be demonstrated through use of CEMS satisfying the requirements of Special Condition 19, as specified. **(TBD)**

C. Compliance with the NH_3 emission standards of subparagraph A shall be demonstrated through use of monitoring methods satisfying the requirements of Special Condition 20, as specified. **(TBD)**

D. The NO_x, CO, and NH_3 emission standards of subparagraph A shall not apply to the Cracking Furnaces (EPNs BA-101 through BA-113, BA-117, and H-101 through H-109) and Boiler (EPN: PK-830) during planned startup and shutdown, and during the following non-routine operations: **(TBD)**

(1) Decoking, defined as the period when the unit is taken off-line to remove carbon deposits and the available hydrocarbon feed valve(s) are in the closed position.

(2) Hot steam standby, defined as the period when the unit is not being decoked, the available hydrocarbon feed valve(s) are in the closed position, and the unit is operating at less than or equal to 50 percent of the maximum rated firing capacity as represented in the permit application.

(3) Load changes, defined as the period beginning when feed rate or fuel composition changes from its prior state and ending when the desired new feed rate or fuel composition is reached. The duration of each load change event shall not exceed 72 hours.

The NH_3 emission standards of subparagraph A in this special condition shall continue to apply during operations specified in subparagraph D until an Alternative Method of Control (AMOC) request pursuant to 30 TAC Chapter 117 is approved. The AMOC application shall be submitted to TCEQ within 120 days upon issuance of TCEQ NSR Project No 385401.

The emissions standards of subparagraph A shall also not apply when the unit is transitioning from non-routine operation to routine operation, and vice versa. In all cases the maximum allowable emission rate shown on the MAERT shall not be exceeded.

11. Fuel used shall be limited to:

A. Cracking Furnaces (EPNs 1592-01A through 1592-07, 1592-38, and H-101 through H-109): plant fuel gas (e.g., mix, tail, and process gas), ethane, or pipeline-quality sweet natural gas. **(6/20)**

B. Flare CB-701 (EPN 1592-16) and Flare CB-710 (EPN1592-40): Pilot and supplemental fuel gas shall be pipeline-quality sweet natural gas and/or plant fuel gas. The pipeline-quality, sweet natural gas combusted in the flares at this facility shall contain no more than 0.25 grain hydrogen sulfide and 5 grains total sulfur per 100 dry standard cubic feet.

C. Flare PK-905 (EPN PK-905): Pilot and supplemental fuel gas shall be pipeline-quality sweet natural gas and/or plant fuel gas. The pipeline-quality, sweet natural gas combusted in the flares at this facility shall contain no more than 2.0 grains hydrogen sulfide and total sulfur per 100 dry standard cubic feet.

Use of any other fuel will require an amendment to the permit.

12. The Wet Air Oxidation (WAO) Unit shall be designed and operated so that it limits sulfur and hydrogen sulfide (H_2S) emissions to the fireboxes of Boilers, BF-801 A, B, and C to 20 ppmv and 5 ppmv, respectively.

13. Opacity of emissions from the fourteen (14) Ethylene Cracking Furnaces (EPNs 1592-01A through 1592-07 and 1592-38) and nine (9) Ethylene Cracking furnaces (H-101 through H-109) shall not exceed five (5) percent averaged over a six-minute period, except for those periods described in Title 30 TAC § 111.111(a)(1)(E). **(9/19)**

Flares

14. Flares CB-701 (EPN 1592-16), and CB-710 (EPN 1592-40) shall be designed and operated in accordance with the following requirements specified in Paragraphs A through F: **(TBD)**

    A. The flare systems shall be designed such that the combined assist natural gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal, upset, and maintenance flow conditions or alternates previously approved by the EPA.

    The heating value and velocity requirements shall be satisfied during operations authorized by this permit or an alternate approved by the EPA. Flare testing per 40 CFR § 60.18(f) may be requested by the appropriate regional office to demonstrate compliance with these requirements.

    B. The flare shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications.

    C. The flare shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. This shall be ensured by the use of steam assist to flares CB-701 and CB-710.

    D. The permit holder shall install a continuous flow monitor and composition analyzer that provides a record of the vent stream flow and composition to the flare. The flow monitor sensor and analyzer sample points shall be installed such that the total vent stream to the flare is measured and analyzed. Readings shall be taken at least once every 15 minutes and the average hourly values of the flow and composition shall be recorded each hour. The monitors shall be calibrated on an annual basis to meet the following accuracy specifications: the flow monitor shall be within plus or minus 5.0%, temperature monitor shall be within plus or minus 2.0% at absolute temperature, and pressure monitor shall be within plus or minus 5.0 mm Hg. Calibration of the analyzer shall follow the procedures and requirements of Section 10.0 of 40 CFR Part 60, Appendix B, Performance Specification 9, as amended through October 17, 2000 (65 FR 61744), except that the multi-point calibration procedure in Section 10.1 of Performance Specification 9 shall be performed at least once every calendar quarter instead of once every month, and the mid-level calibration check procedure in Section 10.2 of Performance Specification 9 shall be performed at least once every calendar week instead of once every 24 hours. The calibration gases used for calibration procedures shall be in accordance with Section 7.1 of Performance Specification 9. Net heating value of the gas combusted in the flare shall be calculated according to the equation given in 40 CFR Section 60.18(f)(3) as amended through October 17, 2000 (65 FR 61744). The monitors and analyzers shall operate as required by this section at least 95% of the time when the flare is operational, averaged over a calendar year. Times required for normal calibration checks are not considered down time to meet the 95% operational rate. Flared gas net heating value and actual exit velocity determined in accordance with 40 CFR Section 60.18(f)(4) shall be measured at least once every 15 minutes and must be recorded as a one-hour block period average heating value and average exit velocity. Hourly mass emission rates shall be determined and recorded using the above readings and the emission factors used in the permit amendment application, PI-1 dated September 30, 2020 or TCEQ Guidance Document factors as appropriate, for flares CB-701 and CB-710. **(TBD)**

E. Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) shall operate in accordance with Special Condition 14, 40 CFR 63 Subpart YY "National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards", Special Conditions 41-59, and Attachment D of these Special Conditions. In addition, Flare CB-701 (EPN 1592-16) shall operate in accordance with AMOC No. 143. Compliance with the requirements of this paragraph shall begin no later than July 6, 2023 and occur as otherwise specified in the AMOC.

Prior to the compliance requirements and schedule of this paragraph, Special Condition Nos. **Error! Reference source not found.**.A through 15.D shall apply to Flares CB-701 and CB-710. After the compliance requirements and schedule of this paragraph are met, Special Condition Nos. 14.E and 14.F shall apply to Flare CB-701 and Special Conditions 14.A through 14.F shall apply to Flare CB-710. If there is a conflict in compliance with paragraphs 14.A through 14.G, Special Conditions 43-61, Attachment D, and AMOC No. 143, then the most stringent requirement shall apply. **(09/23)**

F. The following requirements apply to capture systems for the plant flare systems.

(1) Either conduct a once a month visual, audible, and/or olfactory inspection of the capture system to verify there are no leaking components in the capture system; or verify the capture system is leak-free by inspecting in accordance with 40 CFR Part 60, Appendix A, Test Method 21 once a year. Leaks shall be indicated by an instrument reading greater than or equal to 500 ppmv above background.

(2) The control device shall not have a bypass, or;

If there is a bypass for the control device, comply with either of the following requirements:

(i) Install a flow indicator that records and verifies zero flow at least once every fifteen minutes immediately downstream of each valve that if opened would allow a vent stream to bypass the control device and be emitted, either directly or indirectly, to the atmosphere; or

(ii) Once a month, inspect the valves, verifying the position of the valves and the condition of the car seals that prevent flow out the bypass.

(3) These requirements do not apply to high point vent and low point drain valves. A deviation shall be reported if the monitoring or inspections indicate bypass of the control device when required to be in service per this permit.

(4) If any of the above inspections is not satisfactory, the permit holder shall promptly take necessary corrective action. Records shall be maintained documenting the performance and results of the inspections required above.

G. The low-pressure and high-pressure stages of ground flare (EPN: PK-905) shall be designed and operated in accordance with the design, operating, monitoring, recordkeeping, and reporting requirements of Alternative Method of Control (AMOC) No. 32 in Attachment E. **(TBD)**

The capture systems for the multiple points ground flare (EPN: PK-905) shall comply with requirements specified in Paragraph F of this special condition.

15. The Butadiene Feedstock Pump (EPN 1592-72) shall vent through a carbon adsorption system (CAS) consisting of at least three activated carbon canisters that are connected in series.

A. The CAS shall be sampled twice per week to determine breakthrough of volatile organic compounds (VOC). The sampling point shall be at the outlet of the first canister but before the inlet to the second canister. Sampling shall be done during operating conditions reflecting maximum emission venting to the CAS.

B. The VOC sampling and analysis shall be performed using an instrument with a flame ionization detector (FID), or a TCEQ-approved alternative detector. The instrument/FID must meet all requirements specified in Section 8.1 of EPA Method 21 (40 CFR 60, Appendix A). Sampling and analysis for VOC breakthrough shall be performed as follows:

(1) Immediately prior to performing sampling, the instrument/FID shall be calibrated with zero and span calibration gas mixtures. Zero gas shall be certified to contain less than 0.1 ppmv total hydrocarbons. Span calibration gas shall be methane at a concentration within ± 10 percent of 20 ppmv, and certified by the manufacturer to be ± 2 percent accurate. Calibration error for the zero and span calibration gas checks must be less than ± 5 percent of the span calibration gas value before sampling may be conducted.

(2) The sampling point shall be at the outlet of the first canister but before the inlet to the second canister. Sample ports or connections must be designed such that air leakage into the sample port does not occur during sampling.

(3) During sampling, data recording shall not begin until after two times the instrument response time. The VOC concentration shall be monitored for at least 5 minutes, recording 1-minute averages, during operating conditions reflecting maximum emission venting to the CAS.

C. Breakthrough shall be defined as the highest 1-minute average measured VOC concentration at or exceeding 20 ppmv. When the condition of breakthrough of VOC from the first canister occurs, the waste gas flow shall be switched to the second canister and a fresh canister shall be placed as the new (third) polishing canister within 24 hours. Sufficient new activated carbon canisters shall be maintained at the site to replace spent carbon canisters such that replacements can be done in the above specified time frame.

D. Records of the CAS monitoring maintained at the plant site, shall include (but are not limited to) the following:

(1) Sample time and date.

(2) Monitoring results (ppmv).

(3) Corrective action taken including the time and date of that action.

(4) Process operations occurring at the time of sampling.

E. Alternate monitoring or sampling requirements that are equivalent or better may be approved by the TCEQ Regional Manager or the TCEQ Regulatory Compliance Section Manager. Alternate requirements must be approved in writing before they can be used for compliance purposes.

16. Visual inspection for carbon build up around the stack shall occur once a week. If carbon build up is noticed, it shall be recorded, the CAS shall be shut down, and corrective action shall be taken in accordance with the system maintenance manual.

17. The Emergency Engine (EPN EMGEN-1) shall comply with the following requirements **(9/19):**

A. Fuel for the engine shall be limited to ultra-low sulfur diesel (ULSD) containing no more than 15 ppmw total sulfur.

B. The engine shall be limited to no more than 50 hours per rolling 12-month period during non-emergency situations, as defined at 40 CFR § 63.6640(f).

C. The engine shall be equipped with a non-resettable runtime meter.

D. The engine shall satisfy the Tier 3 exhaust emission standards specified at 40 CFR § 89.112.

E. Compliance with the requirements of paragraph A of this Special Condition shall be demonstrated by retaining a copy of the manufacturers' certificate of conformity, or through other methods receiving prior written approval of the TCEQ Executive Director.

F. A copy of the engine manufacturer's design and operation specifications and all emission-related maintenance requirements must be kept.

G. Records of maintenance activities and the duration of the activity shall be kept for five years.

Initial Determination of Compliance

18. Upon request of the Texas Commission on Environmental Quality (TCEQ) Executive Director, the holder of this permit shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from Cracking Furnaces BA-101 through BA-113 and BA-117, Cracking Furnaces H-101 through H-109, and Boiler PK-830. The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. This requirement may be met using the results of the initial demonstration of compliance and relative accuracy test audit (RATA) required by 30 TAC Chapter 117 for Cracking Furnaces, BA-101 through BA-113 and BA-117. The holder of this permit shall perform inlet sampling and other testing as required to establish the actual pattern and quantities of air contaminants being routed to the fireboxes of the Boilers BF-801A, BF-801B, and BF-801C from the WAO Unit. The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. Results of the testing will be used for estimation of emissions related to operation of the WAO unit and will not be a determination of compliance for operation of the WAO Unit. **(9/19)**

A. The TCEQ Houston Regional Office shall be contacted as soon as testing is scheduled, but not less than 45 days prior to sampling to schedule a pretest meeting.

The notice shall include:

(1) Date for pretest meeting.

(2) Date sampling will occur.

(3) Name of firm conducting sampling.

(4) Type of sampling equipment to be used.

(5) Method or procedure to be used in sampling.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports.

A written proposed description of any deviation from sampling procedures specified in permit conditions or the TCEQ or EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures.

Requests to waive testing for any pollutant specified in B of this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate or equivalent procedure proposals for NSPS testing, which must have the EPA approval, shall be submitted to the TCEQ Regional Director.

B. Air contaminants emitted from the cracking furnaces to be tested for include NO_x. Additional contaminants to be tested for may be requested by the appropriate TCEQ Regional Office. The test method for NO_x shall be the EPA Reference Method 7 or an equivalent procedure approved by the TCEQ. Air contaminants in the WAO vent stream to be tested for include (but are not limited to) H_2S, sulfur compounds, and VOC. The test method for H_2S, sulfur compounds, and VOC shall be a procedure approved by the TCEQ. **(6/20)**

C. Sampling shall occur within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of the facilities and at such other times as may be required by the TCEQ Executive Director or TCEQ Houston Regional Director. Requests for additional time to perform sampling shall be submitted to the TCEQ Houston Regional Office. Additional time to comply with the applicable requirements of 40 CFR Part 60 and 40 CFR Part 61 requires the EPA approval, and requests shall be submitted to the TCEQ Houston Regional Director. If previous sampling performed on the oxidizer is approved by the TCEQ Houston Regional Director, the sampling required by this condition shall be waived.

D. The plant shall operate at maximum production rates during stack emission testing. Primary operating parameters that enable determination of production rates shall be monitored and recorded during the stack test. These parameters are to be determined at the pretest meeting. If these processes are unable to operate at maximum rates during testing, then future production rates may be limited to the rates established during testing. Additional stack testing may be required when higher production rates are achieved. The WAO Unit will operate at maximum spent caustic processing rates during the testing. Primary operating parameters that enable determination of processing rates shall be monitored and recorded during the test. These parameters are to be determined at the pretest meeting. If the WAO process is unable to operate at maximum rates during testing, then future processing rates may be limited to the rates established during testing. Additional testing may be required when higher processing rates are achieved.

E. Copies of the final sampling report shall be forwarded to the TCEQ within 60 days after sampling is completed. Sampling reports shall comply with the attached provisions of

Chapter 14 of the TCEQ Sampling Procedures Manual. The reports shall be distributed as follows:

One copy to the TCEQ Houston Regional Office.

One copy to Harris County Pollution Control Program, Pasadena

Continuous Demonstration of Compliance

19. The holder of this permit shall install, calibrate, and maintain a CEMS to measure and record the in-stack concentrations of NO_x, CO, and O_2, emissions from Cracking Furnaces BA-101 through BA-113 and BA-117, H-101 through H-109 and Boiler PK-830. **(9/19)**

    A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division in Austin for requirements to be met.

    B. The system shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

       Each monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2, with the following exception: a RATA is not required once every four quarters (i.e., four successive quarterly CGA may be conducted). An equivalent quality assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur no closer than two months.

       All CGA exceedances of ±15 percent accuracy and any unscheduled CEMS downtime not corrected within 24 hours shall be reported to the TCEQ Regional Director, and necessary corrective action shall be taken. Unscheduled CEMS downtime is any CEMS downtime not required for daily span checks and annual RATA. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director.

    C. The monitoring data shall be reduced to average hourly concentrations at least once every day, using a minimum of four data points from each one-hour period. Readings shall be taken at least once every 15 minutes quadrant of the clock hour and the average values shall be recorded from for each one-hour period. The individual average concentrations shall be reduced to units of the permit allowable emission rate in tons per year at least once every month. Compliance with the annual allowable contained on the MAERT shall be based on a 12-month rolling average. **(6/20)**

    D. All monitoring data and quality-assurance data shall be maintained by the source for a period of two years and shall be made available to the TCEQ Executive Director or a representative upon request. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

    E. The appropriate TCEQ Regional Office shall be notified at least 15 days prior to any required RATA in order to provide them the opportunity to observe the testing.

F. The CEMS reporting requirements of 30 TAC § 117.119 may be substituted for the reporting requirements if the CEMS is not subject to the requirements of 40 CFR Part 60.

20. The NH_3 concentration in each Exhaust Stack (EPNs H-101 through H-109 and Boiler PK-830) shall be tested or calculated according to one of the methods listed below and shall be tested or calculated according to frequency listed below. Testing for NH_3 slip is only required on days when the SCR unit is in operation. **(9/19)**

The holder of this permit may install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH_3. The NH_3 concentrations shall be corrected and reported in accordance with Special Condition No. 10.

As an approved alternative, the NH_3 slip may be measured using a sorbent or stain tube device specific for NH_3 measurement in the 5 to 10 ppm range. The frequency of sorbent or stain tube testing shall be daily for the first 60 days of operation, after which, the frequency may be reduced to weekly testing if operating procedures have been developed to prevent excess amounts of NH_3 from being introduced in the SCR unit and when operation of the SCR unit has been proven successful with regard to controlling NH_3 slip. Daily sorbent or stain tube testing shall resume when the catalyst is within 30 days of its useful life expectancy. These results shall be recorded and used to determine compliance with Special Condition No. 10.

If the sorbent or stain tube testing indicates an ammonia slip concentration which exceeds 5 parts per million (ppm) at any time, the permit holder shall begin NH_3 testing by either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method (CTM) 27 on a quarterly basis in addition to the weekly sorbent or stain tube testing. The quarterly testing shall continue until such time as the SCR unit catalyst is replaced; or if the quarterly testing indicates NH_3 slip is 4 ppm or less, the Phenol-Nitroprusside/Indophenol/CTM 27 tests may be suspended until sorbent or stain tube testing again indicate 5 ppm NH_3 slip or greater. These results shall be recorded and used to determine compliance with Special Condition No. 10.

As an approved alternative to sorbent or stain tube testing or an NH_3 CEMS, the permit holder may install and operate a second NO_x CEMS probe located upstream of the SCR and after any combustion device, upstream of the stack NO_x CEMS, which may be used in association with the SCR efficiency and NH_3 injection rate to estimate NH_3 slip. This condition shall not be construed to set a minimum NO_x reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance with Special Condition No. 10.

As an approved alternative to sorbent or stain tube testing, NH_3 CEMS, or a second NO_x CEMS, the permit holder may install and operate a dual stream system of NO_x CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NO_x CEMS, and the other exhaust stream would be routed through a NH_3 converter to convert NH_3 to NO_x and then to a second NO_x CEMS. The NH_3 slip concentration shall be calculated from the delta between the two NO_x CEMS readings (converted and unconverted). These results shall be recorded and used to determine compliance with Special Condition No. 10.

Any other method used for measuring NH_3 slip shall require prior approval from the TCEQ Regional Director.

21. After the demonstration of initial compliance for the WAO Unit as required by Special Condition 18, the permit holder shall monitor, on a five year basis, the emissions from the WAO Unit to the fireboxes of Boilers BF-801A, BF-801B, and BF-801C. Air contaminants to be monitored for include sulfur compounds and VOC. Additional contaminants to be tested for may be requested by the appropriate TCEQ Regional Office. The monitoring method for sulfur compounds, VOC, or other compounds shall be a procedure approved by the TCEQ. **(6/20)**

Process Fugitive Monitoring

22. Piping, Valves, Connectors, Pumps, and Compressors in VOC Service for EPNs F-160 and 1592-31 - 28VHP

    Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

    A. The requirements of paragraphs F and G shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure equal to or less than 0.044 lb per square inch, absolute at 68 °F or (2) operating pressure is at least 5 kilopascals (0.725 lb per square inch) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made available upon request.

       The exempted components may be identified by one or more of the following methods:

       (1) piping and instrumentation diagram (PID);

       (2) a written or electronic database or electronic file;

       (3) color coding;

       (4) a form of weatherproof identification; or

       (5) designation of exempted process unit boundaries.

    B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

    C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

    D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by 30 TAC Chapter 115, shall be identified in a list to be made available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in Paragraph A above. If an unsafe to monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe to monitor times. A difficult to monitor component for which quarterly monitoring is specified may instead be monitored annually.

    E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange plug, or second valve must be installed on the line or valve; or

(2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all situations, the open-ended valve or line shall be monitored once with the 72-hour period following the creation of the open ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR Part 60, Appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. A calculated average is not required when all of the compounds in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor and seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shut down as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I or 500 pounds, whichever is greater, the TCEQ Regional Manager and any local programs shall be notified and may require early unit shut down or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC §§ 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

23. Flanges in VOC Service for EPNs F-160 and 1592-31 - 28CNTQ

In addition to the weekly physical inspection required by Item E of Special Condition 22, all accessible connectors in gas/vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items F through J of Special Condition 22

A. Allowance for reduced monitoring frequencies.

(1) The frequency of monitoring may be reduced from quarterly to semiannually if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

(2) The frequency of monitoring may be reduced from semiannually to annually if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

B. If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph. The percent of connectors leaking used in paragraph A shall be determined using the following formula:

$$(Cl + Cs) \times 100/Ct = Cp$$

Where:

Cl = the number of connectors found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Cs = the number of connectors for which repair has been delayed and are listed on the facility shutdown log.

Ct = the total number of connectors in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor connectors.

Cp = the percentage of leaking connectors for the monitoring period.

24. Piping, Valves, Connectors, Pumps, and Compressors in VOC Service for EPNs F-1594 and F-1595 Intensive Directed Maintenance - 28LAER **(9/19)**

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. The requirements of paragraphs F and G shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

The exempted components may be identified by one or more of the following methods:

(1) piping and instrumentation diagram (PID);

(2) a written or electronic database or electronic file;

(3) color coding;

(4) a form of weatherproof identification; or

(5) designation of exempted process unit boundaries.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by 30 TAC Chapter 115, shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. If an unsafe to monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe to monitor times. A difficult to monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance.

Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. In addition, all connectors shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program in accordance with items F thru J of this special condition.

In lieu of the monitoring frequency specified above, connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

The percent of connectors leaking used in paragraph B shall be determined using the following formula:

$$(Cl + Cs) \times 100/Ct = Cp$$

Where:

Cl = the number of connectors found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Cs = the number of connectors for which repair has been delayed and are listed on the facility shutdown log.

Ct = the total number of connectors in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including non-accessible and unsafe to monitor connectors.

Cp = the percentage of leaking connectors for the monitoring period.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

(2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once by the end of the 72 hours period following the creation of the open-ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. Non accessible valves shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves), vent valves on fixed roof tanks, and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs that discharge to the atmosphere, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown. A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR part 60, appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. A calculated average is not required when all of the compounds in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, than the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps, compressors, and agitators shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

All other pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, compressor seals, pump seals, and agitator seals found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days. Records of the first attempt to repair shall be maintained. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown, clearing, and startup as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), or 500 pounds, whichever is greater, the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

I. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator’s log or equivalent.

J. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS), and does not constitute approval of alternative standards for these regulations.

K. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

L. Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

M. If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

N. The percent of valves leaking used in paragraph K shall be determined using the following formula:

$$(Vl + Vs) \times 100/Vt = Vp$$

Where:

Vl = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Vs = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

Vt = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe to monitor valves.

Vp = the percentage of leaking valves for the monitoring period.

O. Any component found to be leaking by physical inspection (i.e., sight, sound, or smell) shall be repaired or monitored with an approved gas analyzer within 15 days to determine whether the component is leaking in excess of 500 ppmv of VOC. If the component is found to be leaking in excess of 500 ppmv of VOC, it shall be subject to the repair and replacement requirements contained in this special condition.

P. Initial component identification and monitoring shall occur within 180 days of initial startup.

Cooling Tower Operating Limits

25. The VOC associated with cooling tower water (EPNs 1592-41 and PK-840) shall be monitored monthly with an approved air stripping system or equivalent. The monitoring method in 30 TAC Chapter 115, Subpart H, Division 2 can be used as an acceptable alternative. The appropriate equipment shall be maintained so as to minimize fugitive VOC emissions from the cooling tower. Faulty equipment shall be repaired at the earliest opportunity but no later than the next scheduled shutdown of the process unit in which the leak occurs. The results of the monitoring and maintenance efforts shall be recorded, and such records shall be maintained for a period of five years. The records shall be made available to the TCEQ Executive Director upon request.

26. Cooling water (EPNs 1592-41 and PK-840) shall be sampled once a week for total dissolved solids (TDS) and once a day or continuously for conductivity. Dissolved solids in the cooling water drift are considered to be emitted as PM_{10}. The data shall result from collection of water samples from the cooling tower feed water and represent the water being cooled in the tower. Water samples should be capped upon collection and transferred to a laboratory area for analysis. The analysis

method for TDS shall be EPA Method 160.1, ASTM D5907, or SM 2540 C [SM - 19th edition of Standard Methods for Examination of Water]. The analysis method for Conductivity shall be ASTM D1125-95 or SM2510 B. Use of an alternative method shall be approved by the TCEQ Regional Director prior to its implementation.

Loading

27. Loading operations at EPN L-103 are limited to the representations submitted in the confidential renewal/amendment application dated September 22, 2015 and the subsequent representations.

    A. All loading shall be submerged and rolling 12-month rack throughput records shall be updated on a monthly basis for each product loaded.

    B. The permit holder shall maintain and update a monthly emissions record which includes calculated emissions of VOC from all loading operations over the previous rolling 12-month period. The record shall include the loading spot, control method used, quantity loaded in gallons, name of the liquid loaded, vapor molecular weight, liquid temperature in degrees Fahrenheit, liquid vapor pressure at the liquid temperature in psia, liquid throughput for the previous month and rolling 12 months to date. Records of VOC temperature are not required to be kept for liquids loaded from unheated tanks which receive liquids at or below ambient temperatures. Emissions shall be calculated using the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Loading Operations."

    C. All lines and connectors shall be visually inspected for any defects prior to hookup. Lines and connectors that are visibly damaged shall be removed from service. Operations shall cease immediately upon detection of any liquid leaking from the lines or connections.

Storage Tanks

28. Tanks will store the materials represented in the confidential file of the renewal/amendment application dated September 29, 2015 and the subsequent representations.

29. The true vapor pressure of any liquid stored at this facility in an atmospheric tank shall not exceed 11.0 psia.

30. Storage tanks FB-704B (EPN 1592-22A) and FB-710 (EPN 1592-28) are subject to the following requirements: The control requirements specified in parts A-E of this condition shall not apply (1) where the VOC has an aggregate partial pressure of less than 0.5 psia at the maximum feed temperature or 95^{o}F, whichever is greater, or (2) to storage tanks smaller than 25,000 gallons.

    A. The tank emissions must be controlled as specified in one of the paragraphs below:

        (1) An internal floating deck or "roof" shall be installed. A domed external floating roof tank is equivalent to an internal floating roof tank. The floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the floating roof: (1) a liquid-mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal.

(2) An open-top tank shall contain a floating roof (external floating roof tank) which uses double seal or secondary seal technology provided the primary seal consists of either a mechanical shoe seal or a liquid-mounted seal and the secondary seal is rim-mounted. A weathershield is not approvable as a secondary seal unless specifically reviewed and determined to be vapor tight.

B. For any tank equipped with a floating roof, the permit holder shall perform the visual inspections and any seal gap measurements specified in Title 40 Code of Federal Regulations § 60.113b (40 CFR § 60.113b) Testing and Procedures (as amended at 54 FR 32973, Aug.11, 1989) to verify fitting and seal integrity. Records shall be maintained of the dates inspection was performed, any measurements made, results of inspections and measurements made (including raw data), and actions taken to correct any deficiencies noted.

C. The floating roof design shall incorporate sufficient flotation to conform to the requirements of API Code 650 dated November 1, 1998 except that an internal floating cover need not be designed to meet rainfall support requirements and the materials of construction may be steel or other materials.

D. Except for labels, logos, etc., not to exceed 15 percent of the tank total surface area, uninsulated tank exterior surfaces exposed to the sun shall be white or unpainted aluminum. Storage tanks must be equipped with permanent submerged fill pipes.

E. The permit holder shall maintain an emission record which includes calculated emissions of VOC from all storage tanks during the previous calendar month and the past consecutive 12-month period. The record shall include tank identification number, control method used, tank capacity in gallons, name of the material stored, VOC molecular weight, VOC monthly average temperature in degrees Fahrenheit, VOC vapor pressure at the monthly average material temperature in psia, VOC throughput for the previous month and year-to-date. Records of VOC monthly average temperature are not required to be kept for unheated tanks which receive liquids that are at or below ambient temperatures.

Emissions from tanks shall be calculated using the methods that were used to determine the MAERT limits in the permit applications and subsequent representations. Sample calculations from the application shall be attached to a copy of this permit at the plant site.

Recordkeeping

31. The permit holder shall continuously monitor fuel gas flow to Cracking Furnaces BA-101 through BA-113, BA-117, and H-101 through H-109 to provide a means of demonstrating continuous compliance with emissions allowables. Records of the average hourly values of the fuel gas flow shall be recorded. A graphical display of the fuel gas flow rate is an acceptable means of recordkeeping. Fuel gas composition shall be measured and recorded at least once weekly. The monitors shall operate as required by this section at least 95% of the time when the cracking furnaces are operational, averaged over a calendar year. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer’s specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent. The records of the average hourly fuel flow and the weekly fuel gas composition measurements shall be maintained for five years and be made available to the TCEQ Executive Director upon request. **(6/20)**

Maintenance Startup and Shutdown (MSS)

32. This permit authorizes emissions from Ethylene Units 1592 (EU 1592), 1594 (EU 1594), and PU-1595 for the planned maintenance, startup, and shutdown (MSS) activities summarized in the MSS Activity Summary (Attachment C) attached to this permit. **(9/19)**

    These emissions are subject to the maximum allowable emission rates indicated on the MAERT.

    Attachment A identifies the inherently low emitting MSS activities that may be performed at the plant. Emissions from activities identified in Attachment A shall be considered to be equal to the potential to emit represented in the permit application. The estimated emissions from the activities listed in Attachment A must be revalidated annually. This revalidation shall consist of the estimated emissions for each type of activity and the basis for that emission estimate.

    Routine maintenance activities, as identified in Attachment B may be tracked through the work orders or equivalent. Emissions from activities identified in Attachment B shall be calculated using the number of work orders or equivalent that month and the emissions associated with that activity identified in the permit.

    The performance of each planned MSS activity not identified in Attachments A or B and the emissions associated with it shall be recorded and include at least the following information:

    A. the physical location at which emissions from the MSS activity occurred, including the emission point number, common name, and any other identifier for the point at which the emissions were released into the atmosphere;

    B. the type of planned maintenance, startup, or shutdown activity and the reason for the planned activity;

    C. the common name and the facility identification number of the facilities at which the MSS activity and emissions occurred;

    D. the date and time of the MSS activity and its duration;

    E. the estimated quantity of each air contaminant, or mixture of air contaminants, emitted with the data and methods used to determine it. The emissions shall be estimated using the methods identified in the amendment application, consistent with good engineering practice.

       MSS activities shall be summed monthly and rolling 12-month emissions shall be updated on a monthly basis.

33. Process units and facilities shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements. Note: Attachment A activities are exempt from these requirements.

    A. The process equipment shall be depressurized to a control device or a controlled recovery system prior to venting to atmosphere, degassing, or draining liquid. Equipment that only contains material that is liquid with VOC partial pressure less than 0.50 psi at the actual process temperature or 95°F may be opened to atmosphere and drained in accordance with paragraph C of this special condition. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded.

B. If mixed phase materials must be removed from process equipment, the cleared material shall be routed to a knockout drum or equivalent to allow for managed initial phase separation. If the VOC partial pressure is greater than 0.50 psi at either the actual process temperature or 95°F, any vents in the system must be routed to a control device or a controlled recovery system. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. Control must remain in place until degassing has been completed or the system is no longer vented to atmosphere.

C. All liquids from process equipment or storage vessels must be removed to the maximum extent practical prior to opening equipment to commence degassing and/or maintenance. Liquids must be drained into a closed vessel unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid must be covered or transferred to a covered vessel within one hour of being drained.

D. If the VOC partial pressure is greater than 0.50 psi at the actual process temperature or 95°F, facilities shall be degassed using good engineering practice to ensure air contaminants are removed from the system through a control device or controlled recovery system to the extent allowed by process equipment or storage vessel design. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. The facilities to be degassed shall not be vented directly to atmosphere, except as necessary to establish isolation of the work area or to monitor VOC concentration following controlled depressurization.

(1) For MSS activities identified in Attachment B, the following option may be used in lieu of (2) below. The facilities being prepared for maintenance shall not be vented directly to atmosphere until the VOC concentration has been verified to be less than 10 percent of the lower explosive limit (LEL) per the site safety procedures.

(2) The locations and/or identifiers where the purge gas or steam enters the process equipment the exit points for the exhaust gases shall be recorded (process flow diagrams [PFDs] or piping and instrumentation diagrams [P&IDs] may be used to demonstrate compliance with the requirement). If the process equipment is purged with a gas, two system volumes of purge gas must have passed through the control device or controlled recovery system before the vent stream may be sampled to verify acceptable VOC concentration prior to uncontrolled venting. The VOC sampling and analysis shall be performed using an instrument meeting the requirements of Special Condition 34. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged. The facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than 10,000 ppmv or 10 percent of the LEL. Documented site procedures used to de-inventory equipment to a control device for safety purposes (i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above. The venting shall be minimized to the maximum extent practicable and actions taken recorded. The control device or recovery system utilized shall be recorded with the estimated emissions from controlled and uncontrolled degassing calculated using the methods that were used to determine allowable emissions for the permit application.

E. Gases and vapors with VOC partial pressure greater than 0.50 psi may be vented directly to atmosphere if all the following criteria are met:

(1) It is not technically practicable to depressurize or degas, as applicable, into the process.

(2) There is not an available connection to a plant control system (flare).

(3) There is no more than 50 lb of VOC to be vented to atmosphere during MSS activity, as applicable.

All instances of venting directly to atmosphere per Special Condition 33.E must be documented when occurring as part of any MSS activity. The emissions associated with venting without control must be included in the calculation basis for those planned MSS activities identified in Attachment B.

34. When required by Special Condition 33.D(2), air contaminant concentration shall be measured using an instrument/detector meeting one set of requirements specified below.

A. VOC concentration shall be measured using an instrument meeting all the requirements specified in EPA Method 21 (40 CFR 60, Appendix A) with the following exceptions:

(1) The instrument shall be calibrated within 24 hours of use with a calibration gas. The calibration gas used and its concentration, and the vapor to be sampled and its approximate response factor (RF), shall be recorded. If the RF of the VOC (or mixture of VOCs) to be monitored is greater than 2.0, the VOC concentration shall be determined as follows

VOC Concentration = Concentration as read from the instrument*RF

(2) Sampling shall be performed as directed by this permit in lieu of section 8.3 of Method 21. During sampling, data recording shall not begin until after two times the instrument response time. The date and time shall be recorded, and VOC concentration shall be monitored for at least 5 minutes, recording VOC concentration each minute. The highest measured VOC concentration shall not exceed the specified VOC concentration limit prior to uncontrolled venting.

B. Colorimetric gas detector tubes may be used to determine air contaminant concentrations if they are used in accordance with the following requirements.

(1) The air contaminant concentration measured is less than 80 percent of the range of the tube. If the maximum range of the tube is greater than the release concentration defined in (3), the concentration measured is at least 20 percent of the maximum range of the tube.

(2) The tube is used in accordance with the manufacturer's guidelines.

(3) At least 2 samples taken at least 5 minutes apart must satisfy the following prior to uncontrolled venting:

measured contaminant concentration (ppmv) < release concentration.

Where the release concentration is:

10,000 times the mole fraction of the total air contaminants present that can be detected by the tube.

The mole fraction may be estimated based on process knowledge. The release concentration and basis for its determination shall be recorded.

Records shall be maintained of the tube type, range, measured concentrations, and time the samples were taken.

C. Lower explosive limit measured with a lower explosive limit detector.

(1) The detector shall be calibrated within 30 days of use with a certified propane, pentane, methane, or ethylene gas standard at 25% of the lower explosive limit (LEL) for propane, pentane, methane, or ethylene. Records of the calibration date/time, calibration result (pass/fail), and calibration gas used shall be maintained.

(2) A functionality test shall be performed on each detector within 24 hours of use using the same certified gas standard used for calibration. The LEL monitor shall read no lower than 90% of the calibration gas certified value. Records, including the date/time and test results, shall be maintained.

35. All permanent facilities must comply with all operating requirements, limits, and representations in this permit during planned startup and shutdown unless alternate requirements and limits are identified in this permit. Alternate requirements for emissions from routine emission points are identified below.

A. Combustion units, with the exception of flares, at this site are exempt from NO_x and CO operating requirements identified in special conditions in other NSR permits during planned startup and shutdown if the following criteria are satisfied.

(1) The maximum allowable emission rates in the permit authorizing the facility are not exceeded.

(2) The startup period does not exceed 8 hours in duration and the firing rate does not exceed 75 percent of the design firing rate. The time it takes to complete the shutdown does not exceed 4 hours.

(3) Control devices are started and operating properly when venting a waste gas stream.

B. A record shall be maintained indicating that the start and end times of each of the activities identified above occur and documentation that the requirements for each have been satisfied.

36. Additional occurrences of MSS activities authorized by this permit (see Attachment A) may be authorized under permit by rule only if conducted in compliance with this permit's procedures, emission controls, monitoring, and recordkeeping requirements applicable to the activity.

37. The following conditions apply to MSS support operations of Boilers BF-801A&B (EPN 1592-10) and BF-801C (EPN 1592-11):

A. For Boilers BF-801A&B (EPN 1592-10) and BF-801C (EPN 1592-11) during MSS support, permit holder shall demonstrate compliance with the short-term nitrogen oxide (NOx) and carbon monoxide (CO) MSS rates on the MAERT using the Boilers CEMS data.

B. Boilers MSS support operations shall be limited to 100 hours/year

C. Permit holder shall keep the following records of Boiler MSS operations for five years:

(1) the date, time and the number of hours/MSS support event,

(2) total hours of Boilers MSS support/year.

(3) For each event, short-term emission rates obtained from CEMs data and annual NOx and CO emissions calculations.

D. The Boilers MSS support records shall be kept at site and shall be made available to the representatives of Texas Commission for Environmental Quality (TCEQ), Environmental Protection Agency (EPA) and any local program having jurisdiction.

38. When boiler EPNs 1592-10 and/or 1592-11 (Boilers BF-801A, BF-801B, and/or BF-801C) are idled for inspection, maintenance or repair, temporary boilers (authorized under Standard Permit No. 120563 or other approved authorization under 30 TAC 106 or 30 TAC 116) may be used to provide necessary steam for plant operations under the following conditions:

A. The use of temporary boilers must be operated such that they are a minor modification, with respect to nonattainment for NO_x, by either:

(1) Having a NO_x emission increase from the temporary boilers of less than 5 tons per year NO_x, or

(2) Ensuring that the emissions increase from the temporary boilers, combined with the emissions reductions from the idling of the permanent boilers, meets the requirements of 30 TAC §116.150(c)(3).

B. Use of temporary boilers prior to beginning the shutdown of the permanent boilers is limited to testing and proving the boilers for operation. The temporary boilers may be brought to operational capacity as part of the shutdown procedures for the permanent boilers to ensure a stable and sufficient steam supply. Likewise, when the permanent boilers are being brought back online, the temporary boilers may remain operational as needed to verify the capability of the permanent boilers and maintain a stable and sufficient steam supply. The temporary boilers should cease operation as soon as practicable once the permanent boilers have been re-commissioned.

C. The facility shall keep records of the project emissions to demonstrate compliance with part A of this special condition.

D. The temporary boilers shall comply as necessary with all other applicable TCEQ or EPA regulations.

39. Catalyst Regeneration Vents (EPNs: 1592-18 (FG-401) and 1592-18A (FG-652/DC-651): Records shall be maintained at the site documenting details to demonstrate that the catalyst regeneration vents (EPNs: 1592-18 and 1592-18A) meet the exemption criteria in 30 TAC §115 Subchapter B, Division 2, Vent Gas Control consistent with 30 TAC § 115.126.(3)-(4). The records shall also include approximate hours per regeneration, number of regenerations per year, and emission calculations based on engineering study and associated test methods performed consistent with the requirements of 30 TAC 115, Subchapter B and H. Emissions from the catalyst regeneration vents (EPNs: 1592-18 and 1592-18A) shall be tracked to ensure compliance with the MAERT emission limits for all the pollutants as represented in the permit amendment application General Application Form PI-1 dated August 26, 2024. Rolling 12-month total emissions shall be used to demonstrate compliance with the annual emission rate. **(08/25)**

Permit by-Rules Referenced

40. The following sources and/or activities listed below are authorized under a Permit by Rule (PBR) by 30 TAC Chapter 106. The list is not intended to be all inclusive and can be altered without modifications to this permit. **(6/20)**

PBR Registration No.	Date Authorized	Permit by Rule Citation	Affected EPNs	Description
114897	2/13/2014	§106.261 & §106.262	1592-31 F-1592-73	Nalco Quench Oil Injection System
132981	7/21/2015	§106.261 §106.262 §106.263 §106.478	1592-90 CPC-FIXMNT F-160	FB-861 Operation Authorization
134693	9/3/2015	§106.261 & §106.262	1592-WWLOAD 1592-WWFRAC	Wastewater and Oily Wastewater Storage and Loading
139001	3/23/2016	§106.261 & §106.262	F-160	Utilities Area Fugitive
			1592-WWLOAD	Spent Caustic Controlled Loading
140351	6/22/2016	§106.261 & §106.262	TOTES 1592-31	Loading & Storage of Anti-Foulant Totes
143865	12/5/2016	§106.261 & §106.262	1592-31 LOAD-TOTE	Tote Loading
173299	7/13/2023	§106.261 & §106.262	F-1594 1592-31	Authorization of open-ended lines in Unit 1592 and 1594 with 97% control efficiency due to safety exemptions.
Unregistered	1975	SE-60 & §106.473	1592-91	Tank FB-202
Unregistered	12/10/2014	§106.472	AD-611CC	WAO Sump AD-611
Unregistered	9/1/1998	§106.472	1592-31 L-1092-NH_3	Ammonia Fugitives Unloading to FA-832
Unregistered	7/1/2018	§106.473	MEOHTOTE	Methanol Totes
Unregistered	2/1/2018	§106.472	S-920CC	WAO Sump
Unregistered	2/1/2018	§106.472	S-948CC	Flare OWS Sump

Special Conditions Applicable to Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40)

41. Installation and Operation of Monitoring and Control Systems on Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) **(09/23)**

    A. The plant site must install and commence operation of the instrumentation, controls, and monitoring systems set forth in Special Conditions 42–45 for the following Flares: Flare CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) except for Newly Installed Covered Flares and Portable Flares installed after June 2, 2022.

    B. The plant site must operate the instrumentation, controls, and monitoring systems for Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) in accordance with Special Conditions 47-49.

    C. Newly Installed Covered Flares and Portable Flares. By no later than the date that any Newly Installed Covered Flare or Portable Flare is In Operation and Capable of Receiving Waste, Supplemental, and/or Sweep Gas, the plant site must have in place and commence operation of the instrumentation, controls, and monitoring systems set forth in Special Conditions 42–45, as specified for Steam-Assisted Flares and Air-Assisted Flares. The plant site must operate the instrumentation, controls, and monitoring systems for Newly Installed Covered Flares and Portable Flares installed after June 2, 2022 in accordance with Special Conditions 42–45 during all times when the Flare is In Operation and Capable of Receiving Waste, Supplemental, and/or Sweep Gas.

42. Vent Gas, Assist Steam, and Assist Air Monitoring Systems. **(09/23)**

    A. For Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40), the plant site must install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of Vent Gas in the header or headers feeding Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40). This system must also be able to continuously analyze pressure and temperature at each point of Vent Gas flow measurement. Different flow monitoring methods may be used to measure different gaseous streams that make up the Vent Gas provided that the flow rates of all gas streams that contribute to the Vent Gas are determined. Flow must be calculated in scfm.

    B. For Steam-Assisted Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40), the plant site must install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of Assist Steam used with Steam-Assisted Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40). This system must also be able to continuously analyze the pressure and temperature of Assist Steam at a representative point of steam flow measurement. Flow must be calculated in scfm.

    C. For each Air-Assisted Flare, the plant site must install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of Assist Air used with each Air- Assisted Flare. If premix assist air and Perimeter Assist Air are both used, the plant site must install, operate, calibrate, and maintain a monitoring system capable of separately continuously measuring, calculating, and recording the volumetric flow rate of premix assist air and Perimeter Assist Air used with that Flare. Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring Assist Air flow rates.

D. Each flow rate monitoring system (whether for a Steam-Assisted Flare or an Air-Assisted Flare) must be able to correct for the temperature and pressure of the system and output parameters in Standard Conditions.

E. In lieu of a monitoring system that directly measures volumetric flow rate, the plant site may choose from the following additional options for monitoring any gas stream:

(1) Mass flow monitors may be used for determining the volumetric flow rate of Assist Steam provided that the plant site converts the mass flow rates to volumetric flow rates pursuant to the methodology in Step 2 of Appendix 1.2;

(2) Mass flow monitors may be used for determining the volumetric flow rate of Vent Gas, provided the plant site determines the molecular weight of such Vent Gas using compositional analysis data collected pursuant to the monitoring method specified in Special Condition 45 and provided that the plant site converts the mass flow rates to volumetric flow rates pursuant to the methodology in Step 2 of Appendix 1.2; and

(3) Continuous pressure/temperature monitoring system(s) and appropriate engineering calculations may be used in lieu of a continuous volumetric flow monitoring system provided the molecular weight of the gas is known and provided the plant site complies with the methodology in Step 2 of Appendix 1.2 for calculating volumetric flow rates. For Vent Gas, the plant site must determine molecular weight using compositional analysis data collected pursuant to the monitoring method specified in Special Condition 45.

43. <u>Assist Steam Control Equipment.</u> The plant site must install and commence operation of equipment, including, as necessary, main and trim control valves and piping which enables the plant site to control Assist Steam flow to Steam-Assisted Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) in a manner sufficient to ensure compliance with these provisions. **(09/23)**

44. <u>Video Camera.</u> The plant site must install and commence operation of a video camera that is capable of monitoring and recording, in digital format, the flame of and any Smoke Emissions from Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40). It is not a violation of this Special Condition or Special Condition 48, however, if a Flare video camera cannot discern the Flare Combustion Zone and/or any Smoke Emissions at Covered Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) subject to these provisions during periods of weather conditions such as fog or snow, provided that recordings are created and retained during these time periods. **(09/23)**

45. <u>Vent Gas Compositional Monitoring or Direct Monitoring of Net Heating Value of Vent Gas.</u> For Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40), the plant site must either determine the concentration of individual components in the Vent Gas or directly monitor the Net Heating Value of the Vent Gas (NHV_{vg}) in compliance with one of the methods specified in this Special Condition. The plant site may elect to use different monitoring methods (of the methods provided in this Special Condition) for different gaseous streams that make up the Vent Gas, provided the composition or Net Heating Value of all gas streams that contribute to the Vent Gas are determined. The plant site must: **(09/23)**

A. Install, operate, calibrate, and maintain a monitoring system capable of continuously measuring (*i.e.*, at least once every 15 minutes), calculating, and recording the individual component concentrations present in the Vent Gas; or

B. Install, operate, calibrate, and maintain a calorimeter capable of continuously measuring (*i.e.*, at least once every 15 minutes), calculating, and recording the NHV*vg* at Standard Conditions. If the plant site elects this method, the plant site may install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the hydrogen concentration in the Vent Gas. The sample extraction point of the calorimeter may be located upstream of the introduction of Supplemental Gas or Sweep Gas or Purge Gas if the composition and flow rate of all such downstream gas(es) is known, and if these known values are then used in the calculation of the Net Heating Value of Vent Gas.

C. If the plant site elects the method in Special Condition 45.A above, and the Net Heating Value of the Vent Gas exceeds the upper calibrated span of the calorimeter on Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40), then the plant site must use the value of the upper calibrated span of that calorimeter for calculating the NHV*vg* at Standard Conditions until the Net Heating Value of the Vent Gas returns to within the measured calibrated span. Use of this method will not constitute instrument system downtime for the period of time that the Net Heating Value of the Vent Gas exceeds the upper calibrated span of the calorimeter.

Direct compositional or Net Heating Value monitoring is not required for purchased ("pipeline quality") natural gas streams. The Net Heating Value of purchased natural gas streams may be determined using annual or more frequent grab sampling at any one representative location. Alternatively, the Net Heating Value of any purchased natural gas stream can be assumed to be 920 BTU/scf.

46. Instrumentation and Monitoring Systems: Optional Equipment. To continuously measure and calculate flow of all Pilot Gas to Flare CB-701 (EPN 1592-16) or CB-710 (EPN 1592-40) in scfm, the plant site, at its option, may either: a) install (if not already installed) an instrument, or b) use a restriction orifice and pressure measurements. The plant site may use the data generated by this instrument or restriction orifice as part of the calculation of the Net Heating Value of the Combustion Zone Gas. **(09/23)**

47. Instrumentation and Monitoring Systems: Specifications, Calibration, Quality Control, and Maintenance. The plant site must comply with Special Conditions 47.A through 47.D, provided, however, the plant site may elect instead to utilize exemptions set forth in 40 C.F.R.§ 63.1103(e)(4)(i) through (ix). **(09/23)**

A. The instrumentation and monitoring systems identified in Special Conditions 42 and 45 must:

(1) Meet or exceed all applicable minimum accuracy, calibration and quality control requirements specified in Table 13 of 40 C.F.R. Part 63, Subpart CC;

(2) Have an associated readout (*i.e.*, a visual display or record) or other indication of the monitored operating parameter that is readily accessible onsite for operational control or inspection by the plant site;

(3) Be capable of measuring the appropriate parameter over the range of values expected for that measurement location; and

(4) Have an associated data recording system with a resolution that is equal to or better than the required instrumentation/system accuracy.

B. The plant site must operate, maintain, and calibrate each instrument and monitoring system identified in Special Conditions 42 and 45 according to a monitoring plan that contains the information listed in 40 C.F.R. § 63.671(b)(1)-(5). However, if the plant site is determining

NHVcz using a process mass spectrometer, the plant site may use the methods established for determining NHVcz in the February 5, 2018 letter to representatives of Extrel CMS, LLC and AMETEK, Energy and Process Division from Steffan M. Johnson, Group Leader, Measurement Technology Group, Office of Air Quality Planning and Standards (attached as Appendix 2.1) in lieu of complying with 40 C.F.R. § 63.671(b)(1)-(5)'s requirements for determining NHVcz using Gas Chromatographs.

C. All gas chromatograph monitoring systems used to comply with Special Condition 45 must also meet the requirements of 40 C.F.R. § 63.671(e)(1) through (3) (Additional Requirements for Gas Chromatographs) regardless of whether the Gas Chromatographs are complying with 40 C.F.R. § 63.671(e)(1)-(3) or the methods outlined in Appendix 2.1.

D. For each instrumentation and monitoring system required by Special Conditions 42 and 45, the plant site must comply with the out-of- control procedures described in 40 C.F.R. § 63.671(c)(1) and (2), and with the data reduction requirements specified in 40 C.F.R. § 63.671(d)(1) through (3).

E. The language in 40 C.F.R. § 63.671, Table 13 of 40 C.F.R. Part 63, Subpart CC, or in any regulatory provision cross-referenced in 40 C.F.R. § 63.671 or Table 13 of 40 C.F.R. Part 63, Subpart CC, that limits the applicability of these regulatory requirements to periods when "regulated material" (as defined in 40 C.F.R. § 63.641) is routed to a Flare, is not applicable for purposes of this Permit. In addition, for purposes of this Permit, the language in 40 C.F.R. § 63.671, Table 13 of 40 C.F.R. Part 63, Subpart CC, or in any regulatory provision cross-referenced in 40 C.F.R. § 63.671 or Table 13 of 40 C.F.R. Part 63, Subpart CC, that refers to a continuous parametric monitoring system will instead be read to refer to the instrumentation and monitoring systems required by Special Conditions 42 and 45.

48. <u>Instrumentation and Monitoring Systems: Recording and Averaging Times.</u> The instrumentation and monitoring systems identified in Special Conditions 42 and 44-45 must be able to produce and record data measurements and calculations for each parameter at the following time intervals: **(09/23)**

Instrumentation and Monitoring System	**Recording and Averaging Times**
Vent gas, Assist Steam Flow, Assist Air Flow, and (if installed) Pilot Gas Flow Monitoring Systems	Measure continuously and record 15-minute block averages
Vent Gas Compositional Monitoring (if using the methodology in Special Condition 45.A)	Measure no less than once every 15 minutes and record that value
Vent Gas Net Heating Value Analyzer (if using the methodology in Special Condition 45.B)	Measure continuously and record 15-minute block averages
Video Camera	Record at a rate of no less than 4 frames per minute

The term "continuously" means to make a measurement as often as the manufacturer's stated design capabilities of the flow monitors (for Vent Gas, Assist Steam, Assist Air, and (if installed) Pilot Gas) and the Vent Gas Net Heating Value Analyzers during each fifteen (15) minute block period, but in no case shall the flow monitors or the Vent Gas Net Heating Value Analyzers make less than one measurement in each fifteen (15) minute block period. The measurement results are then averaged and recorded to represent each fifteen (15) minute block period. Nothing in this

Special Condition prohibits the plant site from setting up process control logic that uses different averaging times from those in this table, provided that the recording and averaging times in this table are available and used for determining compliance with this Permit.

49. Instrumentation and Monitoring Systems: Operation. The plant site must operate each of the instruments and monitoring systems required by Special Conditions 41.C2 and 44-45 and collect data on a continuous basis when Flares CB-701 (EPN 1592-16) or CB-710 (EPN 1592-40) that the instrument and/or monitoring system is associated with is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas, except for the periods of Instrument Downtime specified in Special Conditions 57.A-57.D. **(09/23)**

Determining Whether a Flare Is Not Receiving Potentially Recoverable Gas Flow

50. For Flare CB-701 (EPN 1592-16) which is equipped with a water seal, if all of the following conditions are met, then Flare CB-701 (EPN 1592-16) are not receiving Potentially Recoverable Gas flow: **(09/23)**

   A. For the water seal drum associated with Flare CB-701 (EPN 1592-16), the pressure difference between the inlet pressure and the outlet pressure is less than the water seal pressure as set by the static head of water between the opening of the dip tube in the drum and the water level in the drum;

   B. For the water seal drum associated with Flare CB-701 (EPN 1592-16), the water level in the drum is: (i) at the level of the weir or (ii) if the water level in the drum is measured, the measurement indicates that the water seal is present; and

   C. Downstream of the seal drum, there is no flow of Supplemental Gas directed to Flare CB-701 (EPN 1592-16).

Limitations on Flaring and Flare Gas Recovery

51. Flare Gas Recovery at the Cedar Bayou Plant **(09/23)**

   A. FGRS Capacity and Start-Up. By no later than September 30, 2023, the plant site must complete installation of and commence operation at the Cedar Bayou Plant of a 2,200 scfm FGRS consisting of two online Compressors, each with an FGRS Design Capacity of 1,100 scfm, and a Duplicate Spare Compressor with a capacity of 1,100 scfm (the "Cedar Bayou FGRS").

   B. General. By no later than September 30, 2023, the plant site must operate the FGRS in a manner to minimize Waste Gas to Flare CB-701 (EPN 1592-16) while ensuring safe chemical plant operations. The plant site also must operate the Cedar Bayou FGRS consistent with good engineering and maintenance practices and in accordance with its design and the manufacturer's specifications. Nothing in the Paragraph will require the plant site to recover Non-Recoverable Waste Gas Streams in the Cedar Bayou FGRS.

   C. By no later than June 30, 2024, the Cedar Bayou FGRS must have one Compressor Available for Operation or in operation 98% of the time and two Compressors Available for Operation or in operation 90% of the time. The periods provided for in sub-Paragraphs 51.D and 51.E below may be included in the amount of time that a Compressor is Available for

Operation when determining compliance with the requirement to have one Compressor Available for Operation or in operation 98% of the time.

D. Maintenance of FGRS. Periods of maintenance on and subsequent restart of the Compressors may be included in the amount of time that a Compressor is Available for Operation when determining compliance with the requirement to have one Compressor Available for Operation or in operation 98% of the time; provided however, these periods must not exceed 1,344 hours per Compressor in a five-year rolling sum period, rolled daily. The plant site must use best efforts to schedule maintenance activities during a Turnaround of the process units venting to Flare CB-701 (EPN 1592-16) served by the Cedar Bayou FGRS. To the extent it is not practicable to undertake these maintenance activities during a Turnaround of these units, the plant site must use best efforts to minimize the generation of Waste Gas during such periods.

E. Conditions Outside the FGRS Operating Range. Periods in which the Cedar Bayou FGRS is shut down (including the subsequent restart) due to operating conditions (such as high temperatures or large quantities of entrained liquid in the Vent Gas) outside the design operating range of the Cedar Bayou FGRS, including the associated knock-out drum(s), such that the outage is necessary for safety or to preserve the mechanical integrity of the Cedar Bayou FGRS, may be included in the amount of time that a Compressor is Available for Operation when determining compliance with the requirement to have the Compressor Available for Operation or in operation. By no later than 45 Days after any such outage, the Plant site must investigate the root cause and all contributing causes of the outage and must implement, as expeditiously as practicable, corrective action, if any, to prevent a recurrence of the cause(s).

F. Period to be Used for Computing Percentage of Time. The period of time that a Compressor or group of Compressors must be Available for Operation and/or in operation, as required by sub-Paragraph 51.C, must be determined on a 8,760-hour rolling sum, rolled hourly, using only hours when Potentially Recoverable Gas was generated during all or part of the hour. Any hour when no Potentially Recoverable Gas was generated during the entire hour must be excluded in computing the 8,760-hour rolling sum. The rolling sum must include only the previous 8,760 1-hour periods when Potentially Recoverable Gas was generated during all or part of the hour, provided that the Potentially Recoverable Gas was not generated by flows that could not have been prevented through reasonable planning and were in anticipation of or caused by a natural disaster, act of war or terrorism, or External Utility Loss. Any hour may be excluded in calculating the sum if flows occurred during the hour solely due to, or in anticipation of, a natural disaster, act of war or terrorism, or External Utility Loss and the flows could not have been prevented through reasonable planning.

Flare Combustion Efficiency

52. General Emission Standards Applicable to Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40). The plant site must comply with the requirements set forth in this Special Condition at each Flare at all times when Flare CB-701 (EPN 1592-16) or CB-710 (EPN 1592-40) is In Operation. **(09/23)**

A. Operation during Emissions Venting. The plant site must operate Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) at all times when emissions may be vented to it.

B. No Visible Emissions. The plant site must specify, the smokeless design capacity of each Flare and operate with no Visible Emissions when Flare CB-701 (EPN 1592-16) or CB-710 (EPN 1592-40) is In Operation and the Vent Gas flow is less than the smokeless design capacity of Flare CB-701 (EPN 1592-16) or CB-710 (EPN 1592-40). The plant site must monitor, as specified below in sub-Special Conditions 52.B(1) or 52.B(2), for Visible Emissions from Flare CB-701 (EPN 1592-16) or CB-710 (EPN 1592-40) while it is In Operation. An initial Visible Emissions demonstration must be conducted using an observation period of 2 hours using Method 22 at 40 C.F.R. Part 60, Appendix A–7. Subsequent Visible Emissions observations must be conducted using either method listed in sub-Special Conditions 52.B(1) or 52.B(2). The plant site must record and report any instances where Visible Emissions are observed for more than 5 minutes during any 2 consecutive hours as specified in 40 C.F.R. § 63.655(g)(11)(ii).

(1) At least once per Day, the plant site must conduct Visible Emissions observations using an observation period of 5 minutes using Method 22 at 40 C.F.R. Part 60, Appendix A–7. If at any time the plant site Visible Emissions are observed, even if the minimum required daily Visible Emission monitoring has already been performed, the plant site must immediately begin an observation period of 5 minutes using Method 22 at 40 C.F.R. Part 60, Appendix A–7. If Visible Emissions are observed for more than one continuous minute during any 5- minute observation period, the observation period using Method 22 at 40 C.F.R. Part 60, Appendix A–7 must be extended to 2 hours or until 5 minutes of Visible Emissions are observed.

(2) Alternatively, the plant site may use a video surveillance camera to continuously record (at least one frame every 15 seconds with time and date stamps) images of the Flare flame at a reasonable distance above the Flare flame and at an angle suitable for Visible Emissions observations. The plant site must provide real-time video surveillance camera output to the control room or other continuously staffed location where the camera images may be viewed at any time.

C. Pilot Flame Presence. The plant site must operate Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) with a pilot flame present at all times. The plant site must continuously monitor the presence of the pilot flame(s) using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame is present.

D. Monitoring According to Applicable Provisions. The plant site must comply with all applicable Subparts of 40 C.F.R. Parts 60, 61, or 63 except as provided in Special Condition 57.

E. Good Air Pollution Control Practices. The plant site must at all times, including during periods of startup, shutdown, and/or Malfunction, implement good air pollution control practices to minimize emissions from Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40). Nothing in this sub-Special Condition 52.E requires the plant site to install or maintain Flare monitoring equipment in addition to or different from the equipment required by this Permit.

53. Flare Tip Velocity or Vtip. The plant site must operate Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) in compliance with either sub-Special Condition 53.A or 53.B below, provided that the appropriate monitoring systems are in place, whenever the Vent Gas flow rate is less than the smokeless design capacity of Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40). **(09/23)**

A. The actual Flare Tip Velocity (Vtip) must be less than 60 feet per second. The plant site must monitor Vtip using the procedures specified in Appendix 1.2, or

B. Vtip must be less than 400 feet per second and also less than the maximum allowed Flare Tip Velocity (Vmax) as calculated according to Equation 11 in Appendix 1.2. The plant site must monitor Vtip and gas composition, and must determine NHVvg using the procedures specified in Appendix 1.2. The Unobstructed Cross Sectional Area of the Flare Tip must be calculated consistent with Appendix 1.3.

54. Operation According to Design. The plant site must operate and maintain Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) in accordance with its design and the requirements of this Permit. **(09/23)**

55. Net Heating Value Standards. The plant site must comply with the following Net Heating Value standards, except as provided in Special Conditions 57 (Standard During Instrument Downtime). **(09/23)**

A. Net Heating Value of Combustion Zone Gas (NHV*cz*) for Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) At any time a Flare is In Operation, the plant site must operate Flare CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) so as to maintain the NHV*cz* at or above 270 BTU/scf, as determined on a 15-minute block period basis when Waste Gas is routed to Flare CB-701 (EPN 1592-16) or CB-710 (EPN 1592-40) for at least 15 minutes. The plant site must monitor and calculate NHV*cz* at each Flare in accordance with Appendix 1.2.

B. Dilution Operating Limits for Covered Flares with Perimeter Assist Air (NHVdil). While each Air-Assisted Flare is In Operation, the plant site must maintain the Net Heating Value Dilution parameter (NHVdil) at or above 22 BTU/square foot determined on a 15-minute block period basis, when Waste Gas is routed to the Flare for at least 15 minutes. The plant site must monitor and calculate NHVdil at each Flare that is actively receiving Perimeter Assist Air in accordance with Appendix 1.2.

56. 98% Combustion Efficiency. The plant site must operate Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) with a minimum of a 98% Combustion Efficiency at all times when Waste Gas is vented to the flares. To demonstrate continuous compliance with the 98% Combustion Efficiency, the plant site must operate Steam-Assisted Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) in compliance with Special Condition 55.A and each Air-Assisted Flare in compliance with Special Conditions 55.A and 55.B. **(09/23)**

57. Standard During Instrument Downtime. If one or more of the following conditions (collectively referred to as "Instrument Downtime") is present and renders the plant site incapable of operating Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) in accordance with the applicable NHV standards in Special Condition 55, the plant site must operate Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) in accordance with good air pollution control practices so as to minimize emissions and ensure good combustion efficiency at Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40): **(09/23)**

A. Malfunction of an instrument needed to meet the requirement(s);

B. Repairs following Malfunction of an instrument needed to meet the requirement(s);

C. Recommended scheduled maintenance of an instrument in accordance with the manufacturer's recommended schedule, for an instrument needed to meet the requirement(s); and/or

D. Quality Assurance/Quality Control activities on an instrument needed to meet the requirement(s).

Instrument Downtime must be calculated in accordance with 40 C.F.R. § 60.13(h)(2). In no event must Instrument Downtime exceed 5% of the time in a Semi-Annual Period that Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) are affected by the Instrument Downtime is In Operation. For purposes of calculating the 5%, the time used for NHV Analyzer or gas chromatograph calibration and validation activities may be excluded.

58. <u>Recordkeeping for Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40): Timing and Substance.</u> The plant site must comply with the following recordkeeping requirements: **(09/23)**

A. The plant site must calculate and record each of the following parameters:

(1) Volumetric flow rates of all gas streams that contribute to the Vent Gas volumetric flow rate (in scfm) (in 15-minute block averages and in accordance with any calculation requirements of Special Conditions 42, 48, and Step 2 of Appendix 1.2);

(2) Assist Steam volumetric flow rate (in scfm) (in 15-minute block averages and in accordance with any calculation requirements of Special Conditions 42, 48, and Step 2 of Appendix 1.2);

(3) Assist Air volumetric flow rate (in scfm) (in 15-minute block averages and in accordance with any calculation requirements of Special Conditions 43, 49, and Step 2 of Appendix 1.2);

(4) NHVvg (in BTU/scf) (in 15-minute block averages in accordance with Step 1 of Appendix 1.2);

(5) NHVdil (in BTU/ft2) (in 15-minute block averages in accordance with Step 4 of Appendix 1.2); and

(6) NHVcz (in BTU/scf) (in 15-minute block averages in accordance with Step 3 of Appendix 1.2).

B. For Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40), the plant site must record the duration of all periods of Instrument Downtime for Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) that exceed 5% of the time in a Semi-Annual Period that the Flares CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40) are In Operation. The plant site must record which instrument(s) experienced the downtime, which of Flares CB-701 (EPN 1592-16) or CB-710 (EPN 1592-40) were affected by the downtime, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that the plant site took.

C. The plant site must record the dates and times of any periods that the plant site deviates from the standards in Special Condition 51. The plant site must also record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that the plant site took.

D. At any time that the plant site deviates from the emissions standards in Special Conditions 55-57 at either Flare CB-701 (EPN 1592-16) or CB-710 (EPN 1592-40), the plant site must record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that the plant site took.

Fenceline Monitoring Project Requirements

59. The plant site must install, maintain, and operate a Fenceline Monitoring Project in accordance with Appendix 2.2. **(09/23)**

Date: TBD

Permit Numbers 1504A, PSDTX748M2, and N148M3

Attachment A

Inherently Low Emitting Activities

Activity	**Emissions**				
	VOC			PM	
Calibration of analytical equipment	X				
Carbon can replacement	X				
Catalyst charging/handling				X	
Instrumentation/analyzer maintenance	X				
Meter proving – Flare	X				
Replacement of analyzer filters and screens	X				
Maintaining sight glasses	X				

Date: June 14, 2019

Permit Numbers 1504A, PSDTX748M2, and N148M3
Attachment B

Routine Planned Maintenance Activities

The following maintenance activities are authorized by this permit:

- Converters
- Drier maintenance
- Filter Replacement
- Pump repair/replacement
- Fugitive component (valve, pipe, flange, PSV, etc.) repair/replacement
- Compressor repair/replacement
- Heat exchanger repair/replacement
- Instrumentation repair/replacement (> inherently low emitting sources)
- Vessel repair/replacement
- Miscellaneous equipment repair/replacement (e.g. valves, piping, spools, specialty equipment, etc)
- Process vent system maintenance
- Catalyst handling

Date: June 12, 2020

Permit Numbers 1504A, PSDTX748M2, and N148M3
Attachment C

MSS Activity Summary

Facilities	Description	Emissions Activity	EPN
See Attachment A	miscellaneous low emitting activities	See Attachment A	F-MSSEU FMSSEU1594 FMSSPU1595
See Attachment A	miscellaneous low emitting activities	vent to flare	1592-16 1592-40 PK-905
See Attachment B	process unit routine maintenance, component repair or replacement - depressurize, degas and drain	vent to flare	1592-16 1592-40 PK-905
See Attachment B	process unit routine maintenance - equipment opening	vent to atmosphere	F-MSSEU FMSSEU1594 FMSSPU1595
EU 1592 EU 1594 PU 1595	process unit shutdown - depressurize, degas and drain	vent to flare	1592-16 1592-40 PK-905
EU 1592 EU 1594 PU 1595	process unit shutdown - equipment opening	vent to atmosphere	F-MSSEU FMSSEU1594 FMSSPU1595
EU 1592 EU 1594 PU 1595	process unit startup	vent to flare	1592-16 1592-40 PK-905
See Attachment A	miscellaneous low emitting activities	See Attachment A	F-MSSEU FMSSEU1594 FMSSPU1595
EU-1592	Unit startup & shutdown – Boilers support	Vent to atmosphere	1592-10 1592-11
Vent FG-401 and FG-652 / DC-651	Catalyst regeneration maintenance	See Special Condition 39	1592-18 1592-18A

VOC emission limits have been included for the flares (EPN's 1592-16 and 1592-40 and PK-905) to prepare equipment for maintenance or emissions generated from the activity itself (e.g. compressor repair). VOC emissions generated when opening the equipment to the atmosphere are included in the permit wide F-MSSEU, FMSSEU1594, and FMSSPU1595 EPNs.

Date: August 29, 2025

Permit Numbers 1504A, PSDTX748M2, and N148M3
Attachment D

Appendix 1.1-1.3 and 2.1-2.2

Appendix 1.1 – Incorporated Consent Decree Definitions

The definitions in Appendix 1.1 of Attachment D are only applicable to Special Conditions 41-59 of this permit.

"Air-Assisted Flare" or "Air_{asst}" means a Flare that uses Assist Air to assist in combustion.

"Assist Air" means all air that is intentionally introduced before or at a Flare tip through nozzles or other hardware conveyance for the purposes of, including, but not limited to, protecting the design of the Flare tip, promoting turbulence for mixing, or inducing air into the flame. Assist Air includes premix assist air and Perimeter Assist Air. Assist Air does not include surrounding ambient air.

"Assist Steam" means all steam that is intentionally introduced before or at a Flare tip through nozzles or other hardware conveyance for the purposes of, including, but not limited to, protecting the design of the Flare tip, promoting turbulence for mixing, or inducing air into the flame. Assist Steam includes, but is not necessarily limited to, center steam, lower steam, and upper steam.

"Available for Operation" means, with respect to a Compressor within a Flare Gas Recovery System ("FGRS"), that the Compressor is capable of commencing the recovery of Potentially Recoverable Gas as soon as practicable but not more than one hour after the Need for a Compressor to Operate arises. The period of time, not to exceed one hour, allowed by this definition for the startup of a Compressor will be included in the amount of time that a Compressor is Available for Operation.

"Backup Flare" means a Flare that is permanently installed and that receives Waste Gas only when the Waste Gas has been redirected to it from a Covered Flare.

"BTU/scf" means British Thermal Unit per standard cubic foot.

"Calendar Quarter" means a three-month period ending on March 31, June 30, September 30, or December 31.

"Capable of Receiving Sweep, Supplemental, and/or Waste Gas" means, for a Flare, that the flow of Sweep Gas, Supplemental Gas, and/or Waste Gas is not prevented from being directed to the Flare by means of an isolation device such as closed valves, blinds, or stopples.

"Cedar Bayou Flares" means the following Steam-Assisted Flares and Air- Assisted Flares located at the Cedar Bayou Plant:

- CB-701 (EPN 1592-16) (Steam-Assisted)
- CB-710 (EPN 1592-40) (Steam-Assisted)

"Cedar Bayou Plant" means the petrochemical manufacturing plant owned and operated by the plant site, located at 9500 I-10 East, Baytown, Texas 77521-9570.

"Combustion Efficiency" or "CE" means a Flare's efficiency in converting the organic carbon compounds found in Combustion Zone Gas to carbon dioxide. Combustion Efficiency must be determined in accordance with the NHV_{cz} calculations in Appendix 1.2.

“Combustion Zone” means the area of the Flare flame where the Combustion Zone Gas combines for combustion.

“Combustion Zone Gas” means all gases and vapors found after the Flare tip. This gas includes all Vent Gas, Pilot Gas, Total Steam, and Assist Air.

“Compressor” means, with respect to a FGRS, a mechanical device designed and installed to recover gas from a flare header. Types of FGRS compressors include reciprocating compressors, centrifugal compressors, liquid ring compressors, screw compressors, and liquid jet ejectors.

“Covered Air-Assisted Flares” means each of the Flares that are Air-Assisted Flares.

“Covered Flare” or “Covered Flares” means each of the following Flares, as well as any Newly Installed Covered Flare, Portable Flare, or Backup Flare in use at the plant, provided however that once a Covered Flare is permanently taken out of service and that change is reported in the subsequent Semi-Annual Report, that Flare is no longer a Covered Flare:

- Flares: CB-701 (EPN 1592-16) and CB-710 (EPN 1592-40).

“Covered Steam-Assisted Flares” means each of the Covered Flares that are Steam-Assisted Flares.

“Day” means a calendar day unless expressly stated to be a business day. In computing any period of time for a compliance deadline, where the last day would fall on a Saturday, Sunday, or federal or state holiday, the period will run until the close of business of the next business day.

“Design Capacity” means, with respect to a FGRS, the sum of the capacities, in mscf per Day, of the installed flare gas recovery Compressors, excluding the capacity of any installed Duplicate Spare Compressor or warehouse spare Compressor.

“Duplicate Spare Compressor” means, with respect to a Flare Gas Recovery System, an installed compressor, designed to be identical or functionally equivalent to the other compressor(s) of the FGRS. In order to qualify as a “Duplicate Spare Compressor,” the compressor must be functionally interchangeable with the other FGRS compressor(s) such that the Design Capacity of the FGRS is Available for Operation while any one compressor of the FGRS is out of service.

“External Utility Loss” means a loss in the supply of electrical power or other third-party utility to a Covered Plant that is caused by actions occurring outside the boundaries of a Covered Plant, excluding utility losses due to an interruptible utility service agreement.

“Flare” means a combustion device lacking an enclosed combustion chamber that uses an uncontrolled volume of ambient air to burn gases.

“Flare Gas Recovery System” or “FGRS” means a system of one or more Compressors, piping, and associated water seal, rupture disk, or other equipment used to divert gas from a Flare and direct the gas to a fuel gas system, to a combustion device other than the Flare, or to a product, co-product, by-product, or raw material recovery system.

“Flare Tip Velocity” or “V_{tip}” means the velocity of gases exiting the Flare tip as defined in Special Condition 53.

“In Operation,” with respect to a Flare, means all times that Sweep, Supplemental, or Waste Gas is or may be vented to a Flare. A Flare that is In Operation is Capable of Receiving Sweep, Supplemental, or Waste Gas unless all Sweep, Supplemental, and Waste Gas flow is prevented by means of an isolation device such as closed valves, blinds, and/or stopples.

"Malfunction" means, as specified in 40 C.F.R. § 60.2, any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions.

"Monitoring System Malfunction" means any sudden, infrequent, and not reasonably preventable failure of instrumentation or a monitoring system to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Monitoring System Malfunctions.

"MMSCFD" or "mmscfd" means million standard cubic feet per Day.

"MMSCFH" or "mmscfh" means million standard cubic feet per hour.

"MSCFH" of "mscfh" means thousand standard cubic feet per hour.

"Net Heating Value" or "NHV" means the theoretical total quantity of heat liberated by the complete combustion of a unit volume or weight of a fuel initially at 25 degrees Centigrade and 760 mmHg, assuming that the produced water is vaporized and all combustion products remain at, or are returned to, 25 degrees Centigrade; however, the standard for determining the volume corresponding to one mole is 20 degrees Centigrade.

"Net Heating Value Analyzer" or "NHV Analyzer" means an instrument capable of measuring the Net Heating Value of Vent Gas in BTU/scf. The sample extraction point of a Net Heating Value Analyzer may be located upstream of the introduction of Supplemental Gas and/or Sweep Gas and/or Purge Gas if the composition and flow rate of any such Supplemental Gas and/or Sweep Gas and/or Purge Gas is known and if this known value then is used in the calculation of the Net Heating Value of the Vent Gas.

"Net Heating Value of Combustion Zone Gas" or "NHV_{cz}" means the Net Heating Value, in BTU/scf, of the Combustion Zone Gas in a Flare. NHV_{cz} must be calculated in accordance with Step 3 of Appendix 1.2.

"Net Heating Value of Dilution" or "NHVdil" means the Net Heating Value, in BTU/ft^2, of the dilution zone gas in a Flare. NHV_{dil} must be calculated in accordance with Step 4 of Appendix 1.2.

"Net Heating Value of Vent Gas" or "NHV_{vg}" means the Net Heating Value, in BTU/scf, of the Vent Gas directed to a Flare. NHV_{vg} must be calculated in accordance with Step 1 of Appendix 1.2.

"Newly Installed Covered Flare(s)" means any Flare (including any Backup Flare) that is permanently installed, receives Waste Gas that has been redirected to it from Flares 1592-16 or 1592-40.

"Non-Recoverable Waste Gas Stream(s)" means any of the following specific gas streams that are not recoverable by an FGRS:

1. Regeneration Waste Gas Streams produced during the regeneration and subsequent nitrogen sweeping of the dryers, reactors, and other vessels at the Covered Plants. Regeneration Waste Gas Streams are high in nitrogen (typically approximately 90%) and have very low heating value (typically approximately 100 BTU/scf), thus they are not a useful fuel;

2. Methanator Waste Gas Streams generated during the startup or shutdown of the Methanator. The Methanator Waste Gas Streams are high in nitrogen (typically approximately greater than 90% nitrogen) and have a very low heating value (typically approximately 100 BTU/scf), thus they are not a useful fuel; and

3. Nitrogen purges at the Cedar Bayou Plant generated from process units during startup, shutdown, or a Turnaround (either partial or complete plant Turnaround) that cause the NHV of the fuel gas

exiting the fuel gas drum, as currently measured by analyzer AI_8002 (or by a subsequently installed monitor downstream of the fuel gas drum), to fall below 740 BTU/scf.

"Perimeter Assist Air" means the portion of Assist Air introduced at the perimeter of the Flare tip or above the Flare tip. Perimeter Assist Air includes air intentionally entrained in lower and upper steam. Perimeter Assist Air includes all Assist Air except premix assist air.

"Pilot Gas" means gas introduced into a Flare tip that provides a flame to ignite the Vent Gas.

"Portable Flare" means any Flare that is not permanently installed and that receives Waste Gas that has been redirected to it from Flares 1592-16 or 1592-40.

"Potentially Recoverable Gas" means the Sweep Gas, Supplemental Gas, and/or Waste Gas (including hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, and/or water) directed to a Covered Flare's or group of Covered Flares' FGRS, except that Non-Recoverable Waste Gas Streams are not included in the definition of "Potentially Recoverable Gas."

"Prevention Measure" means an instrument, device, piece of equipment, system, process change, physical change to process equipment, procedure, or program to minimize or eliminate flaring.

"Purge Gas" means the gas introduced between a Flare header's water seal and the Flare tip to prevent oxygen infiltration (backflow) into the Flare tip. For a Flare with no water seal, the function of Purge Gas is performed by Sweep Gas, and therefore, by definition, such a Flare has no Purge Gas.

"Smoke Emissions" shall have the definition set forth in Section 3.5 of Method 22 of 40 C.F.R. Part 60, Appendix A. Smoke Emissions may be either documented by a video camera or determined by an observer knowledgeable with respect to the general procedures for determining the presence of Smoke Emissions per Method 22.

"Standard Conditions" means a temperature of 68 degrees Fahrenheit and a pressure of 1 atmosphere. Unless otherwise expressly set forth in this Consent Decree or an Appendix, Standard Conditions apply.

"Steam-Assisted Flare" means a Flare that uses Assist Steam to assist in combustion.

"Supplemental Gas" means all gas introduced to a Flare in order to improve the combustible characteristics of the Combustion Zone Gas.

"Sweep Gas" means:

1. For a Flare with an FGRS: Gas intentionally introduced into a Flare header system to prevent oxygen buildup in the Flare header. Sweep Gas in these Flares is introduced prior to and recovered by the FGRS

2. For a Flare without an FGRS: Gas intentionally introduced into a Flare header system to maintain a constant flow of gas through the Flare header and out the Flare tip in order to prevent oxygen building in the Flare header and to prevent infiltration (backflow) into the Flare tip.

"Total Steam" means the total of all steam that is supplied to a Flare and includes, but is not limited to, lower steam, center steam, and upper steam.

"Turnaround" means a complete shutdown of any emission unit to: (1) perform necessary cleaning and repairs; (2) perform required tests and internal inspections; and/or (3) install any modifications or additions, or make preparations necessary for a future modification or addition.

“Unassisted Flare” means a Flare that does not use Assist Steam or Assist Air.

“Unobstructed Cross Sectional Area of the Flare Tip” or “$A_{tip-unob}$” means the open, unobstructed area of a Flare tip through which Vent Gas and center steam pass. Diagrams of four common Flare types are set forth in Appendix 1.3 together with the equations for calculating the $A_{tip-unob}$ of these four types.

“Vent Gas” means all gas found just before the Flare tip. This gas includes all Waste Gas, that portion of Sweep Gas that is not recovered, Purge Gas, and Supplemental Gas, but does not include Pilot Gas, Total Steam, or Assist Air.

“Visible Emissions” means five minutes or more of Smoke Emissions during any two consecutive hours.

“Waste Gas” means the mixture of all gases from facility operations that is directed to a Flare for the purpose of disposing of the gas. “Waste Gas” does not include gas introduced to a Flare exclusively to make it operate safely and as intended; therefore, “Waste Gas” does not include Pilot Gas, Total Steam, Assist Air, or the minimum amount of Sweep Gas and Purge Gas that is necessary to perform the functions of Sweep Gas and Purge Gas. “Waste Gas” also does not include the minimum amount of gas introduced to a Flare to comply with regulatory and/or enforceable permit requirements regarding the combustible characteristics of Combustion Zone Gas; therefore, “Waste Gas” does not include Supplemental Gas. Depending upon the instrumentation that monitors Waste Gas, certain compounds (hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, and/or water (steam)) that are directed to a Flare for the purpose of disposing of these compounds may be excluded from calculations relating to Waste Gas flow.

Appendix 1.2 – Calculating Combustion Efficiency, Net Heating Value of the Combustion Zone Gas (NHV_{cz}), the Net Heating Value Dilution Parameter (NHV_{dil}), and Flare Tip Velocity

All abbreviations, constants, and variables are defined in the Key included in this Appendix.

Combustion Efficiency Equation:

$$CE = [CO_2]/([CO_2] + [CO] + [OC])$$

where:

$[CO_2]$ = Concentration in volume percent or ppm-meters of carbon dioxide in the combusted gas immediately above the Combustion Zone

$[CO]$ = Concentration in volume percent or ppm-meters of carbon monoxide in the combusted gas immediately above the Combustion Zone

$[OC]$ = Concentration in volume percent or ppm-meters of the sum of all organic carbon compounds in the combusted gas immediately above the Combustion Zone, counting each carbon molecule separately where the concentration of each individual compound is multiplied by the number of carbon atoms it contains before summing (e.g., 0.1 volume percent ethane shall count as 0.2 percent OC because ethane has two carbon atoms)

For purposes of using the CE equation, the unit of measurement for CO_2, CO, and OC must be the same; that is, if “volume percent” is used for one compound, it must be used for all compounds. “Volume percent” cannot be used for one or more compounds and “ppm-meters” for the remainder.

Step 1: Determine the Net Heating Value of the Vent Gas (NHV_{vg})

The plant site shall determine the Net Heating Value of the Vent Gas (NHV_{vg}) based on composition monitoring data on a 15-minute block average basis according to the following requirements. If the plant site monitors separate gas streams that combine to comprise the total Vent Gas flow to Flare CB-701 (EPN 1592-16) or Flare CB-710 (EPN 1592-40), the 15-minute block average Net Heating Value shall be determined separately for each measurement location according to the following requirements and a flow-weighted average of the gas stream Net Heating Values shall be used to determine the 15-minute block average Net Heating Value of the cumulative Vent Gas. The NHV_{vg} 15-minute block averages shall be calculated for set 15-minute time periods starting at 12 midnight to 12:15 AM, 12:15 AM to 12:30 AM and so on, concluding at 11:45 PM to midnight.

Step 1a: Equation or Output to be Used to Determine NHV_{vg} at a Measurement Location

For any gas stream for which the plant site complies with Special Condition 45 by collecting compositional analysis data in accordance with the method set forth in Special Condition 45.a: Equation 1 shall be used to determine the NHVvg of a specific sample by summing the Net Heating Value for each individual component by individual component volume fractions. Individual component Net Heating Values are listed in Table 1 of this Appendix.

$$NHV_{vg} = \sum_{i=1}^{n}(x_i \cdot NHV_i) \qquad \textbf{Equation 1}$$

For any gas stream for which the plant site complies with Paragraph 45 by collecting direct Net Heating Value monitoring data in accordance with the method set forth in 44.b but for which a Hydrogen Concentration Monitor is not used: Use the direct output (measured value) of the monitoring system(s) (in BTU/scf) to determine the NHVvg for the sample.

For any gas stream for which the plant site complies with Paragraph 45 by collecting direct Net Heating Value monitoring data in accordance with the method set forth in 44.b and for which a Hydrogen Concentration Monitor is also used: Equation 2 shall be used to determine the NHVvg for each sample measured via the Net Heating Value monitoring system. Where hydrogen concentration data is collected, Equation 2 performs a net correction for the measured heating value of hydrogen since the theoretical Net Heating Value for hydrogen is 274 Btu/scf, but for the purposes of this Consent Decree, a Net Heating Value of 1,212 Btu/scf may be used (1,212 – 274 = 938 BTU/scf).

$$NHV_{vg} = NHV_{measured} + 938x_{H2} \qquad \textbf{Equation 2}$$

Step 1b: Calculation Method to be Used in Applying Equation/Output to Determine NHV$_{vg}$

For Flare CB-701 or Flare CB-710 for which the plant site complies with Paragraph 46 by using a continuous monitoring system in accordance with the method set forth in 45.A or 45.B: The plant site may elect to determine the 15-minute block average NHV$_{vg}$ using either the Feed-Forward Calculation Method or the Direct Calculation Method (both described below). The plant site need not elect to use the same methodology at all Flares with a continuous monitoring system; however, for each such Flare, the plant site must elect one calculation method that will apply at all times and use that method for all continuously monitored flare vent streams associated with that Flare. If the plant site intends to change the calculation method that applies to a Flare, the plant site must notify the EPA 30 Days in advance of such a change.

Feed-Forward Calculation Method. When calculating NHV$_{vg}$ for a specific 15-minute block:

1. Use the results from the first sample collected during an event (for periodic Vent Gas flow events) for the first 15-minute block associated with that event.

2. If the results from the first sample collected during an event (for periodic Vent Gas flow events) are not available until after the second 15-minute block starts, use the results from the first sample collected during an event for the second 15-minute block associated with that event.

3. For all other cases, use the results that are available from the most recent sample prior to the 15-minute block period for that 15-minute block period for all Vent Gas streams. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 AM and the analysis is completed at 12:38 AM, the results are available at 12:38 AM and these results would be used to determine compliance during the 15-minute block period from 12:45 AM to 1:00 AM.

Direct Calculation Method. When calculating NHV$_{vg}$ for a specific 15-minute block:

1. If the results from the first sample collected during an event (for periodic Vent Gas flow events) are not available until after the second 15-minute block starts, use the results from the first sample collected during an event for the first 15-minute block associated with that event.

2. For all other cases, use the arithmetic average of all NHV$_{vg}$ measurement data results that become available during a 15-minute block to calculate the 15-minute block average for that period. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 AM and the analysis is completed at 12:38 AM, the results are available at 12:38 AM and these results would be used to determine compliance during the 15-minute block period from 12:30 AM to 12:45 AM.

Step 2: Determine Volumetric Flow Rates of Gas Streams

The plant site shall determine the volumetric flow rate in standard cubic feet (scf) of Vent Gas, along with the volumetric flow rates (in scf) of any Supplemental Gas, Assist Steam, and Premix Assist Air, over a 15-minute block average basis. The 15-minute block average volumetric flow rates shall be calculated for set 15-minute time periods starting at 12 midnight to 12:15 AM, 12:15 AM to 12:30 AM and so on, concluding at 11:45 PM to midnight.

For any gas streams for which the plant site complies with Special Condition 42 by using a monitoring system that directly records volumetric flow rate: Use the direct output (measured value) of the monitoring system(s) (in scf), as corrected for the temperature and pressure of the system to standard conditions (i.e., a temperature of 20°C (68 °F) and a pressure of 1 atmosphere) to then calculate the average volumetric flow rate of that gas stream for the 15- minute block period.

For Vent Gas, Assist Steam, or Premix Assist Air gas streams for which the plant site complies with Special Condition 42 by using a mass flow monitor to determine volumetric flow rate: Equation 3 shall be used to determine the volumetric flow rate of Vent Gas, Assist Air, or Assist Steam by converting mass flow rate to volumetric flow at standard conditions (i.e., a temperature of 20°C (68 °F) and a pressure of 1 atmosphere). Equation 3 uses the molecular weight of the gas stream as an input to the equation; therefore, if the plant site elects to use a mass flow monitor to determine volumetric flow rate of Vent Gas, the plant site must collect compositional analysis data for such Vent Gas in accordance with the method set forth in 55.A. For Assist Steam, use a molecular weight of 18 pounds per pound-mole. For Assist Air, use a molecular weight of 29 pounds per pound-mole. The converted volumetric flow rates at standard conditions from Equation 3 shall then be used to calculate the average volumetric flow rate of that gas stream for the 15-minute block period.

$$Q_{vol} = \frac{Q_{mass} * 385.3}{MWt} \qquad \textbf{Equation 3}$$

For gas streams for which the molecular weight of the gas is known and for which the plant site complies with Special Condition 42 by using continuous pressure/temperature monitoring system(s): Use appropriate engineering calculations to determine the average volumetric flow rate of that gas stream for the 15-minute block period. For Assist Steam, use a molecular weight of 18 pounds per pound-mole. For Assist Air, use a molecular weight of 29 pounds per pound-mole. For Vent Gas, molecular weight must be determined by collecting compositional analysis data for such Vent Gas in accordance with the method set forth in 44.A.

Step 3: Calculate the Net Heating Value of the Combustion Zone Gas (NHV_{cz})

For Flare CB-701 (EPN 1592-16) or Flare CB-710 (EPN 1592-40) at which: 1) the Feed-Forward Calculation Method is used; 2) gas composition or Net Heating Value monitoring is performed in a location representative of the cumulative vent gas stream; and 3) Supplemental Gas flow additions to the Flare are directly monitored: Equation 4 shall be used to determine the 15-minute block average NHV_{cz} based on the 15-minute block average Vent Gas, Supplemental Gas, and assist gas flow rates.

$$NHV_{cz} = \frac{(Q_{vg} - Q_{NG2} + Q_{NG1}) * NHV_{vg} + (Q_{NG2} - Q_{NG1}) * NHV_{NG}}{Q_{vg} + Q_{s} + Q_{a,premix}} \qquad \textbf{Equation 4}$$

For the first 15-minute block period of an event, Q_{NG1} shall use the volumetric flow value for the current 15-minute block period (i.e. $Q_{NG1} = Q_{NG2}$). NHV_{NG} shall be determined using one of the following methods: 1) direct compositional or Net Heating Value monitoring of the natural gas stream in accordance with Step 1; or 2) for purchased (“pipeline quality”) natural gas streams, the plant site may elect to either: a) use annual or more frequent grab sampling at any one representative location, or b) assume a Net Heating Value of 920 BTU/scf.

For all other Flares: Equation 5 shall be used to determine the 15-minute block average NHV_{cz} based on the 15-minute block average Vent Gas and assist gas flow rates. For periods when there is no Assist Steam flow or Premix Assist Air flow, $NHV_{cz} = NHV_{vg}$.

$$NHV_{cz} = \frac{(Q_{vg}) * NHV_{vg}}{Q_{vg} + Q_s + Q_{a,premix}} \quad \textbf{Equation 5}$$

Step 4: Calculate the Net Heating Value Dilution Parameter (NHV_{dil})

For Flare CB-701 (EPN 1592-16) or Flare CB-710 (EPN 1592-40) at which: 1) the Feed-Forward Calculation Method is used; 2) gas composition or Net Heating Value monitoring is performed in a location representative of the cumulative Vent Gas stream; and 3) Supplemental Gas flow additions to the Flare are directly monitored: Equation 6 shall be used to determine the 15-minute block average NHV_{dil} only during periods when Perimeter Assist Air is used. For 15-minute block periods when there is no cumulative volumetric flow of Perimeter Assist Air, the 15-minute block average NHV_{dil} parameter does not need to be calculated.

$$NHV_{dil} = \frac{[(Q_{vg} - Q_{NG2} + Q_{NG1}) * NHV_{vg} + (Q_{NG2} - Q_{NG1}) * NHV_{NG}] * Diam}{(Q_{vg} + Q_s + Q_{a,premix} + Q_{a,perimeter})} \quad \textbf{Equation 6}$$

For the first 15-minute block period of an event, Q_{NG1} shall use the volumetric flow value for the current 15-minute block period (i.e., $Q_{NG1} = Q_{NG2}$). NHV_{NG} shall be determined using one of the following methods: 1) direct compositional or Net Heating Value monitoring of the natural gas stream in accordance with Step 1; or 2) for purchased ("pipeline quality") natural gas streams, the plant site may elect to either: a) use annual or more frequent grab sampling at any one representative location, or b) assume a Net Heating Value of 920 BTU/scf.

For all other Flares: Equation 7 shall be used to determine the 15-minute block average NHV_{dil} based on the 15-minute block average vent gas and Perimeter Assist Air flow rates, only during periods when Perimeter Assist Air is used. For 15-minute block periods when there is no cumulative volumetric flow of Perimeter Assist Air, the 15-minute block average NHV_{dil} parameter does not need to be calculated.

$$NHV_{dil} = \frac{Q_{vg} * Diam * NHV_{vg}}{(Q_{vg} + Q_s + Q_{a,premix} + Q_{a,perimeter})} \quad \textbf{Equation 7}$$

Step 5: Ensure that during Flare operation, $NHV_{cz} \geq 270$ BTU/scf

The Flare must be operated to ensure that NHVcz is equal to or above 270 BTU/scf, as determined for each 15-minute block period when Supplemental, Sweep, and/or Waste Gas is routed to a Flare for at least 15-minutes. Equation 8 shows this relationship.

$$NHV_{cz} \geq 270\ BTU/scf \quad \textbf{Equation 8}$$

Step 6: Ensure that during Flare operation, $NHV_{dil} \geq 22$ BTU/ft^2

A Flare actively receiving Perimeter Assist Air must be operated to ensure that NHV_{dil} is equal to or above 22 BTU/ft^2, as determined for each 15-minute block period when Supplemental, Sweep, and/or Waste Gas is routed to a Flare for at least 15-minutes. Equation 9 shows this relationship.

$$NHV_{dil} \geq 22\ BTU/ft^2 \quad \textbf{Equation 9}$$

Calculation Method for Determining Compliance with V_{tip} Operating Limits.

The plant site shall determine V_{tip} on a 15-minute block average basis according to the following requirements:

(a) The plant site shall use design and engineering principles and the guidance in Appendix 1.3 to determine the Unobstructed Cross Sectional Area of the Flare Tip. The Unobstructed Cross Sectional Area of the Flare Tip is the total tip area that Vent Gas can pass through. This area does not include any stability tabs, stability rings, and Upper Steam or air tubes because Vent gas does not exit through them.

(b) The plant site shall determine the cumulative volumetric flow of Vent Gas for each 15-minute Block Average Period using the data from the continuous flow monitoring system required in Paragraph 52 according to the requirements in Step 2 above.

(c) The 15-minute block average V_{tip} shall be calculated using Equation 10.

$$V_{tip} = \frac{Q_{cum}}{Area_x 900}$$ **Equation 10**

(d) If the plant site chooses to comply with Paragraph 64.B, the site shall also determine the NHV_{vg} using Step 1 above and calculate V_{max} using Equation 11 in order to compare V_{tip} to V_{max} on a 15-minute Block average basis.

$$log_{10}(V_{max}) = \frac{NHV_{vg} + 1{,}212}{850}$$ **Equation 11**

Key to the Abbreviations:

385.3 = Conversion Factor (scf/lb-mol)

850 = Constant

900 = Conversion Factor (seconds/15-minute block average)

1,212 = Constant

Area = The unobstructed cross sectional area of the flare tip is the total tip area that vent gas can pass through, in ft^2. This area does not include any stability tabs, stability rings, and upper steam or air tubes because Vent gas does not exit through them. Use design and engineering principles to determine the unobstructed cross sectional area of the flare tip.

Diam = Effective diameter of the unobstructed area of the flare tip for Vent gas flow, in ft. Determine the diameter as

$$Diam = 2 * \sqrt{Area \div \pi}$$

i = individual component in Vent Gas (unitless)

MWt = molecular weight of the gas at the flow monitoring location (lb/lb-mol)

n = number of components in Vent Gas (unitless)

NHV_{cz} = Net Heating Value of Combustion Zone Gas (BTU/scf)

NHV_i = Net Heating Value of component I according to Table 1 of this Appendix (BTU/scf)

$NHV_{measured}$ = Net Heating Value of Vent Gas stream as measured by monitoring system (BTU/scf)

NHV_{NG} = Net Heating Value of Supplemental Gas to flare during the 15-minute block period (BTU/scf)

NHV_{vg} = Net Heating Value of Vent Gas (BTU/scf)

$Q_{a,perimeter}$ = cumulative volumetric flow of perimeter assist air during the 15-minute block period (scf)

$Q_{a,premix}$ = cumulative volumetric flow of premix assist air during the 15-minute block period (scf)

Q_{cum} = cumulative volumetric flow over 15-minute block average period (scf)

Q_{mass} = mass flow rate (pounds per second)

Q_{NG1} = cumulative volumetric flow of Supplemental Gas to flare during previous 15-minute block period (scf)

Q_{NG2} = cumulative volumetric flow of Supplemental Gas to flare during the 15-minute block period (scf)

Q_{S} = cumulative volumetric flow of Total Steam during the 15-minute block period (scf)

Q_{vg} = cumulative volumetric flow of Vent gas during the 15-minute block period (scf)

Q_{vol} = volumetric flow rate (scf per second)

V_{max} = Maximum allowed flare tip velocity (feet per second)

V_{tip} = Flare tip velocity (feet per second)

x_{i} = concentration of component i in Vent gas (vol fraction)

x_{H2} = concentration of H2 in Vent Gas at time sample was input into NHV monitoring system (vol fraction)

Table 1
Individual Component Properties

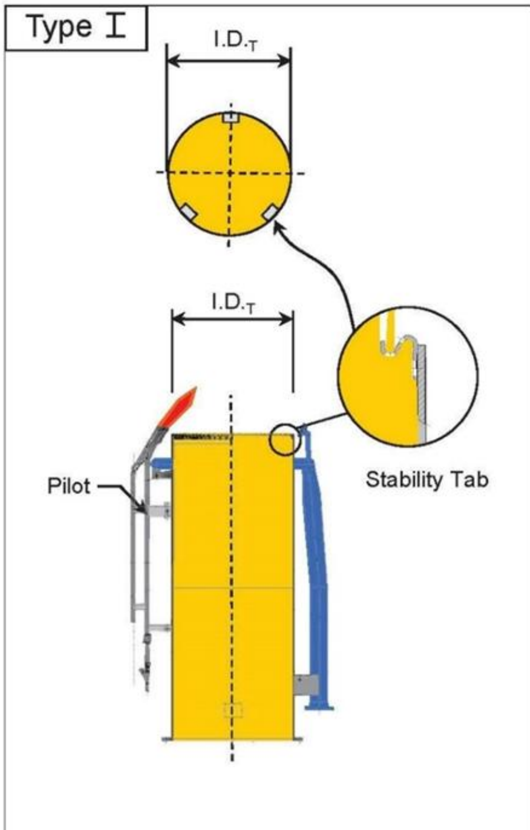
Component	Molecular Formula	MW_i (pounds per pound-mole)	CMN_i (mole per mole)	NHV_i (British thermal units per standard cubic foot)	LFL_i (volume %)
Acetylene	C_2H_2	26.04	2	1,404	2.5
Benzene	C_6H_6	78.11	6	3,591	1.3
1,2-Butadiene	C_4H_6	54.09	4	2,794	2.0
1,3-Butadiene	C_4H_6	54.09	4	2,690	2.0
iso-Butane	C_4H_{10}	58.12	4	2,957	1.8
n-Butane	C_4H_{10}	58.12	4	2,968	1.8
cis-Butene	C_4H_8	56.11	4	2,830	1.6
iso-Butene	C_4H_8	56.11	4	2,928	1.8
trans-Butene	C_4H_8	56.11	4	2,826	1.7
Carbon Dioxide	CO_2	44.01	1	0	∞
Carbon Monoxide	CO	28.01	1	316	12.5
Cyclopropane	C_3H_6	42.08	3	2,185	2.4
Ethane	C_2H_6	30.07	2	1,595	3.0
Ethylene	C_2H_4	28.05	2	1,477	2.7
Hydrogen	H_2	2.02	0	1,212[A]	4.0
Hydrogen Sulfide	H_2S	34.08	0	587	4.0
Methane	CH_4	16.04	1	896	5.0
Methyl-Acetylene	C_3H_4	40.06	3	2,088	1.7
Nitrogen	N_2	28.01	0	0	∞
Oxygen	O_2	32.00	0	0	∞
Pentane+ (C5+)	C_5H_{12}	72.15	5	3,655	1.4
Propadiene	C_3H_4	40.06	3	2,066	2.16
Propane	C_3H_8	44.10	3	2,281	2.1
Propylene	C_3H_6	42.08	3	2,150	2.4
Water	H_2O	18.02	0	0	∞

[A]The theoretical Net Heating Value for hydrogen is 274 Btu/scf, but for the purposes of this Permit, a Net Heating Value of 1,212 Btu/scf shall be used.

Note: If a component is not specified in this Table 1, the heats of combustion may be determined using any published values where the net enthalpy per mole of offgas is based on combustion at 25°C and 1 atmosphere (or constant pressure) with offgas water in the gaseous state, but the standard temperature for determining the volume corresponding to one mole of vent gas is 20°C.

Appendix 1.3 - Calculating the Unobstructed Cross Sectional Area of Various Types of Flare Tips

Type I



$$A_{tip\text{-}unob} = \pi (I.D._T)^2/4 - (X_T * A_{ST})$$

Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._T$ = Inside Diameter Flare Tip

X_T = Number of Stability Tabs

A_{ST} = Area of a Stability Tab

Example: $I.D._T$ = 41.5 inches

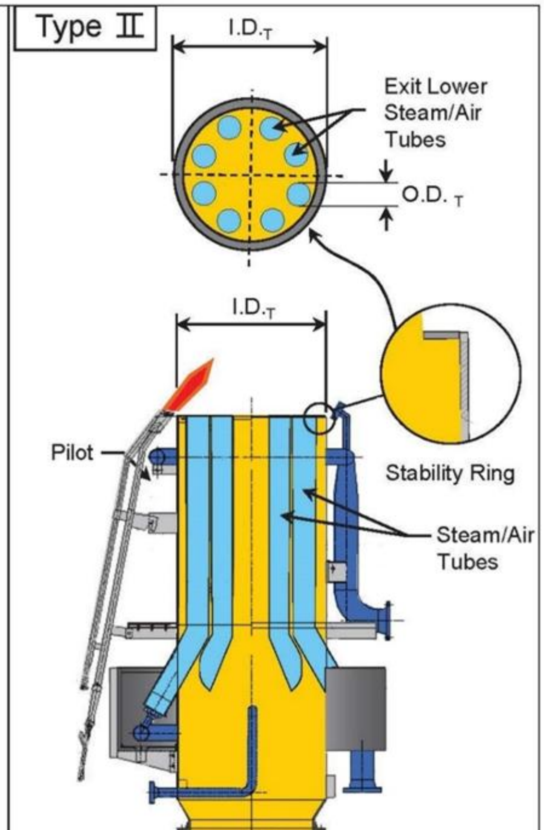
$X_T = 3$

A_{ST} = 3 Sq. inches

$A_{tip\text{-}unob} = \pi (41.5)^2/4 - (3 * 3)$

$A_{tip\text{-}unob}$ = 1344 Sq. inches

Type II



$$A_{tip\text{-}unob} = \pi (I.D._T)^2/4 - A_{ST} - N_T * \pi * (O.D._T)^2/4$$

Where: $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._T$ = Inside Diameter Flare Tip

A_{ST} = Area of Stability Ring

$O.D._T$ = Outside Diameter of Steam/Air Tubes

N_T = Number of Steam/Air Tubes

Example: $I.D._T$ = 47.5 inches

A_{ST} = 100 Sq. inches

$O.D._T$ = 6.5 inches

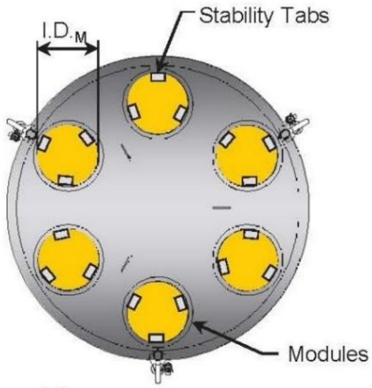
$N_T = 8$

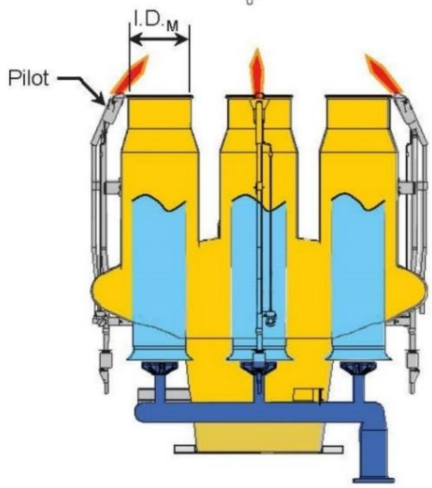
$A_{tip\text{-}unob} = \pi (47.5)^2/4 - 100 - 8 * \pi * (6.5)^2/4$

$A_{tip\text{-}unob}$ = 1322 Sq. inches

Appendix 1.3 - Calculating the Unobstructed Cross Sectional Area of Various Types of Flare Tips

Type III





$$A_{tip\text{-}unob} = N_M * (\pi * (I.D._M)^2/4 - X_T * A_{ST})$$

Where:

$A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._M$ = Inside Diameter of One Tip Module

N_M = Number of Modules

X_T = Number of Stability Tabs per Module

A_{ST} = Area of a Stability Tab

Example: $I.D._M$ = 17 inches

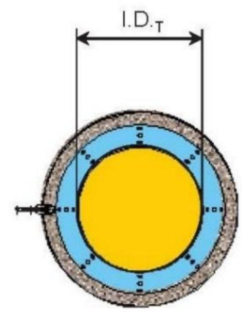
$N_M = 6$ $X_T = 3$

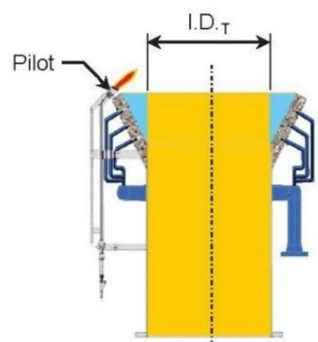
A_{ST} = 3 Sq. inches

$A_{tip\text{-}unob} = 6 * (\pi * (17)^2/4 - 3 * 3)$

$A_{tip\text{-}unob}$ = 1308 Sq. inches

Type IV





$$A_{tip\text{-}unob} = \pi (I.D._T)^2/4$$

Where:

$A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip

$I.D._T$ = Inside Diameter of Flare Tip

Example: $I.D._T$ = 41.5 inches

$A_{tip\text{-}unob} = \pi (41.5)^2/4$

$A_{tip\text{-}unob}$ = 1353 Sq. inches

Appendix 2.1 - February 5, 2018, Johnson Letter

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

FEB 05 2018

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

Mr. Chuck DeCarlo
Marketing Manager
Extrel CMS, LLC
575 Epsilon Drive, Suite 2
Pittsburg, PA 15238-2838

Mr. Tony Slapikas
Product Manager for Mass Spectrometry
AMETEK, Energy & Process Division
150 Freeport Road
Pittsburgh, PA 15238

Dear Mr. DeCarlo and Mr. Slapikas,

I am writing in response to your letter dated August 18, 2017, requesting approval for use of process mass spectrometers as part of an alternative to testing procedures utilizing calorimeters or gas chromatographs to measure Net Heating Value (NHV_{VG}) in flare vent gas as required under 40 CFR Part 63, Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries. The owner or operator of facilities subject to Subpart CC must measure flare vent gas composition to determine NHV_{VG} in units of British Thermal Units per standard cubic foot (BTU/SCF). This BTU/SCF determination may be performed using a calorimeter capable of continuously measuring, calculating, and recording NHV_{VG} at standard conditions (40 CFR 63.670 (j)(3)) or equipment that determines the concentration of individual components in the flare vent gas (40 CFR 63.670 (j)(1)), such as a gas chromatograph, and, if desired, may directly measure the hydrogen concentration in the flare vent gas following the methods provided in 40 CFR 63.670 (j)(4). All monitoring equipment must meet the applicable minimum accuracy, calibration and quality control requirements specified in Table 13 and §63.671 of Subpart CC.

In your letter, you propose to use a process mass spectrometer analyzer and the following measurement approach as an alternative to measure NHV_{VG}:

1) The owner or operator of the affected facility will perform a pre-survey to determine the list and concentration of components that are present in flare vent gas feed. This pre-survey will be used in part to:
   a) Determine an appropriate analysis method for the site-specific refinery flare vent gas;
   b) Create a list of vent gas components to be included in calibration gas cylinders to be used to evaluate the quality of the measurement procedure used to determine NHV_{VG};
   c) Define calibration standards to be prepared by a vendor at a certified accuracy of 2 percent and traceable to NIST; and
   d) Perform an initial calibration to identify mass fragment overlap and response factors for the target compounds.

Appendix 2.1 - February 5, 2018, Johnson Letter

2) The process mass spectrometer will be calibrated using calibration gas standards consisting of a mix of the compounds identified in the site specific flare gas pre-survey.
3) During flare gas analysis, compounds that are not identified during the pre-survey and that have mass fragments identical to the compounds found during the pre-survey will be included in the calculation of NHV_{VG}.
4) Calibration error (CE) for each component in the calibration blend will be calculated using the following equation:

$$CE = \frac{C_m - C_a}{C_a} x\ 100$$

Where :

C_m = Average instrument response, (ppm)
C_a = Cylinder gas value or tag value, (ppm)

5) The average instrument CE for each calibration compound at any calibration concentration must not differ by more than 10 percent from the cylinder gas value or tag value.
6) For each set of triplicate injections at each calibration concentration for each calibration compound, any one introduction shall not deviate more than 5 percent from the average concentration measured at that level.

Your supporting information included Method 301 calculations that showed acceptable bias and precision when you measured a mixture of gases from a vendor certified gas cylinder. Your request also includes reference to facilities needing to monitor flare gas composition continuously to effectively maintain flare efficiency while compensating for changes in the flare gas composition.

With this letter, we are approving your request to substitute continuous process mass spectrometry for continuous gas chromatography as allowed in 40 CFR 63.670 and 63.671 predicated on both your proposed use of these process mass spectrometers as described above and the additional provisos listed below:

1) You must meet the requirements in 40 CFR 63.671 (e)(1) and (2) including Table 13 requirements for Net Heating Value by Gas Chromatograph.
2) You may use the alternative sampling line temperature allowed in 40 CFR 63, Subpart CC, Table 13, under Net Heating Value by Gas Chromatograph.
3) You must meet applicable Performance Specification 9 (40 CFR part 60, appendix B) requirements for initial continuous monitoring system acceptance including, but not limited to:
    - Performing a multi-point calibration check at three concentrations following the procedure in Section 10.1; and
    - Performing periodic process mass spectrometer calibrations as directed for gas chromatographs in 40 CFR 63, Subpart CC, Table 13.
4) You may augment the minimum list of calibration gas components found in 40 CFR 63.671(e) with compounds found during the pre-survey as needed to develop a site-specific analysis method.

5) For unknown gas components that have similar analytical mass fragments to calibration compounds, you may report the unknowns as an increase in the overlapped calibration gas compound.
6) For unknown compounds that do not produce mass fragments that overlap calibration compounds, you may use the response factor for the nearest molecular weight hydrocarbon in the calibration mix to quantify the unknown component's NHV_{VG}. This requirement parallels the requirements in 40 CFR Part 63.671 (e)(3) for gas chromatographs.
7) You may use the response factor for n-pentane to quantify any unknown components detected with a higher molecular weight than n-pentane.
8) You must meet all other applicable generic requirements of §§63.670 and 63.671 for measurement of NHV_{VG} (i.e., measurement requirements not specifically targeted to gas chromatographs).
9) A copy of this approval letter must be included in the report for each testing program where these alternative testing procedures are applied.

Since this alternative test method approval under 40 CFR 63.7 (f) is appropriate for use at all facilities subject to 40 CFR 63, Subpart CC, we will announce on EPA's Web site (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*) that the alternative method is broadly applicable to determination of NHV_{VG} under this subpart.

If you have any questions regarding this approval or need further assistance, please contact Ray Merrill at (919) 541-5225 or *merrill.raymond@epa.gov*, or Robin Segall at (919) 541-0893 or *segall.robin@epa.gov*.

Sincerely,

Robin R. Segall for SMJ

Steffan M. Johnson, Group Leader
Measurement Technology Group

cc.

Gerri Garwood, EPA/OAQPS/SPPD
Maria Malave, EPA/OECA/OC
Brenda Shine, EPA/OAQPS/SPPD
EPA Regional Testing Contacts

Appendix 2.2 – Fenceline Monitoring Requirements

1. **Applicability.** The requirements of this Fenceline Monitoring Project apply to the Cedar Bayou Plant.

   A. The Cedar Bayou Plant must install Fenceline Monitoring Systems in accordance with Paragraphs 2-3 of this Appendix.

   B. Reserved

2. **Timing and Public Transparency.** No later than 270 Days after the Effective Date, the site must submit in writing to EPA a report: a) showing the location of all monitors that will be utilized to comply with the Monitoring Requirements of Paragraph 3 below; b) providing an active/live/not password protected URL to a mockup of the publicly available website to be used to report monitoring data pursuant to this Fenceline Monitoring Project; and c) a statement indicating that the website is properly indexed (including, but not limited to the following search terms, "benzene," "fenceline monitoring," and the Plant name and location) with the major search engines (e.g., Google, Bing, Yahoo) to allow the public to easily find the website.

   The Fenceline Monitoring Systems described in the Paragraph 3 below must commence collecting data no later than 365 Days after the June 2, 2022.

   The site must post to a publicly available website each individual sample result for each monitor, each biweekly annual average concentration difference value (once annual averages are available), and any corrective action plan submitted to EPA pursuant to Paragraph 3(h) (corrective action plans posted to the website may be redacted to protect confidential business information). The site must post each individual sample result for each monitor within 30 Days of the end of the bi-weekly sampling period or within 30 Days after sampling collected pursuant to the "alternative sampling frequency for burden reduction" requirements set forth in Paragraph 3(f)(3) below. The site must post each annual average difference value within 45 Days of the sampling period that allows the creation of a new annual average difference value. The data must be presented in a tabular format.

3. **Monitoring Requirements.**

   A. The site must commence sampling along the property boundary of the Cedar Bayou Plant. The site must collect and analyze the samples in accordance with Methods 325A and 325B of Rule Appendix A and sub-Paragraphs 3(a) through 3(i).

   B. The target analyte for the Fenceline Monitoring Systems is benzene.

   C. <u>Siting of monitors</u>. The site must determine the passive monitor locations comprising each Fenceline Monitoring System in accordance with Section 8.2 of Method 325A of Rule Appendix A, with the exception of the number of duplicates and blanks, which will be determined pursuant to 40 C.F.R. § 63.658(c)(3).

      (1) As it pertains to this Fenceline Monitoring Project, known sources of VOCs, as used in Section 8.2.1.3 in Method 325A of Rule Appendix A for siting passive monitors means a wastewater treatment unit, process unit, or any emission source requiring HAP control according to the requirements of any state or federal air permit applicable to the Covered Plant, including marine vessel loading operations. For marine vessel loading operations that are located offshore, one passive monitor should be sited on the shoreline adjacent to the dock. For purposes of this Appendix, an additional monitor is not required if the only emission sources within 50 meters of the monitoring boundary are equipment leak sources satisfying all of the requirements in 40 C.F.R. § 63.658(c)(1)(i) through (iv).

(2) If there are 19 or fewer monitoring locations, the site shall collect at least one co-located duplicate sample per sampling period and at least one field blank per sampling period. If there are 20 or more monitoring locations, the site shall collect at least two co- located duplicate samples per sampling period and at least one field blank per sampling period. The co-located duplicates may be collected at any one of the perimeter sampling locations.

(3) The site must follow the procedure in Section 9.6 of Method 325B of Rule Appendix A to determine the detection limit of benzene for each sampler used to collect samples and co-located samples and blanks. Each monitor used to conduct sampling in accordance with this Appendix must have a detection limit that is at least an order of magnitude lower than the benzene action level.

(4) Reserved.

D. The site may submit and discuss additional data collected by it or by third parties in the reports required pursuant to Paragraph 3.h of this Appendix. If the site concludes that an exceedance of the Action Level described in Paragraph 3.g is caused by an offsite source(s), such a conclusion does not relieve the site of its obligation to perform the Root Cause investigation described in Paragraph 3.h.

E. Collection of meteorological data. The site must collect and record meteorological data according to the applicable requirements in sub-Paragraphs 3(e)(1) and 3(e)(2).

(1) The site must collect and record the average temperature and barometric pressure during each sampling period using either an on-site meteorological station in accordance with Section 8.3 of Method 325A of Rule Appendix A or, alternatively, using data from a United States Weather Service (USWS) meteorological station provided the USWS meteorological station is within 40 kilometers (25 miles) of the applicable Covered Plant.

(2) If an on-site meteorological station is used, the site must follow the calibration and standardization procedures for meteorological measurements in EPA-454/B-08-002 and at:

http://www3.epa.gov/ttnamti1/files/ambient/met/Volume_IV_Meteorological_Measurements.pdf

F. Sampling Frequency. The site must use a sampling period and sampling frequency as specified in this sub-Paragraph 3(f).

(1) Sampling period. A 14-Day sampling period must be used, unless a shorter sampling period is determined to be necessary under Paragraph 3(h). A sampling period is defined as the period during which a sampling tube is deployed at a specific sampling location with the diffusive sampling end cap in-place. The sampling period does not include the time required to analyze the sample. For the purpose of this sub-Paragraph, a 14-Day sampling period may be no shorter than 13 calendar days and no longer than 15 calendar days, but the routine sampling period must be 14 calendar days.

(2) Base sampling frequency. Except as provided in Paragraph 3(f)(3), the frequency of sample collection must be once each contiguous 14-Day sampling period, such that the next 14-Day sampling period begins immediately upon the completion of the previous 14- Day sampling period.

(3) Alternative sampling frequency for burden reduction. When an individual monitor consistently, as defined in sub-Paragraph 3(f)(3)(i) through (v), yields results at or below 0.9 micrograms per cubic meter ($\mu g/m^3$), the site may elect to use the applicable minimum sampling frequency specified in Paragraph 3(f)(3)(i) through (v), for that individual monitoring site. When calculating Δc (as defined in Paragraph 3(g))

for the monitoring period when using this alternative for burden reduction, zero must be substituted for the sample result for the monitoring site for any period where a sample is not taken.

(i) If every sample at an individual monitoring site is at or below 0.9 µg/m^3 for 2 years (52 consecutive samples), every other sampling period can be skipped for that individual monitoring site, i.e., sampling can occur approximately once per month.

(ii) If every sample at an individual monitoring site that is monitored at the frequency specified in Paragraph 3(f)(3)(i) is at or below 0.9 µg/m^3 for 2 years (i.e., 26 consecutive "monthly" samples), five 14-Day sampling periods can be skipped for that individual monitoring site following each period of sampling, i.e., sampling will occur approximately once per quarter.

(iii) If every sample at an individual monitoring site that is monitored at the frequency specified in Paragraph 3(f)(3)(ii) is at or below 0.9 µg/m^3 for 2 years (i.e., 8 consecutive quarterly samples), twelve 14-Day sampling periods can be skipped for that individual monitoring site following each period of sampling, i.e., sampling will occur twice a year.

(iv) If every sample at an individual monitoring site that is monitored at the frequency specified in Paragraph 3(f)(3)(iii) is at or below 0.9 µg/m^3 for 2 years (i.e., 4 consecutive semi-annual samples), only one sample per year is required for that individual monitoring site. For yearly sampling, samples must occur at least 10 months but no more than 14 months apart.

(v) If at any time a sample for an individual monitoring site that is monitored at the frequency specified in Paragraphs 3(f)(3)(i) through (iv) returns a result that is above 0.9 µg/m^3, that sampling site must return to the original sampling requirements of contiguous 14-Day sampling periods with no skip periods for one quarter (six 14-Day sampling periods). If every sample collected during this quarter is at or below 0.9 µg/m^3, the sites may revert back to the reduced monitoring frequency applicable for that individual monitoring site immediately prior to the sample reading exceeding 0.9 µg/m^3. If any sample collected during this quarter is above 0.9 µg/m^3, that individual monitoring site must return to the original sampling requirements of contiguous 14- Day sampling periods with no skip periods for a minimum of two years. The burden reduction requirements can be used again for that monitoring site once the requirements of Paragraph 3(f)(3)(i) are met again, i.e., after 52 contiguous 14-Day samples with no results above 0.9 µg/m^3.

G. Action Level. Within 45 Days of completion of each sampling period, the site, must determine whether the results are above or below the action level as follows:

(1) Calculation of the Δc. The site must determine the benzene difference concentration (Δc) for each 14-Day sampling period by determining the highest and lowest sample results for benzene concentrations from the sample pool and calculating the Δc as the difference in these concentrations. The site must adhere to the following procedures when one or more samples for the sampling period are below the method detection limit for benzene:

(i) If the lowest detected value of benzene is below detection, the site must use zero as the lowest sample result when calculating Δc.

(ii) If all sample results are below the method detection limit, the site must use the method detection limit as the highest sample result.

(2) The site must calculate the annual average Δc based on the average of the 26 most recent 14-Day sampling periods. The site must update this annual average value after

receiving the results of each subsequent 14-Day sampling period (i.e., on a "rolling" basis).

(3) The action level for benzene is 9 μg/m^3 on an annual average basis. If the annual average Δc value for benzene is less than or equal to 9 μg/m3, the concentration is below the action level. If the annual average Δc value for benzene is greater than 9 μg/m^3, the concentration is above the action level, and the site must conduct a root cause analysis and corrective action in accordance with Paragraph 3(h)

H. Root Cause Analysis and Corrective Action. Within 5 Days of determining that the action level has been exceeded for any annual average Δc and no longer than 50 Days after completion of the sampling period, the site, must initiate a root cause analysis to determine the cause of such exceedance and to determine appropriate corrective action, such as those described in Paragraphs 3(h)(1) through (4). The root cause analysis and initial corrective action analysis must be completed and initial corrective actions taken no later than 45 Days after determining there is an exceedance. Root cause analysis and corrective action may include, but is not limited to:

(1) Leak inspection using Method 21 of 40 C.F.R. Part 60, Appendix A-7 and repairing any leaks found.

(2) Leak inspection using optical gas imaging and repairing any leaks found.

(3) Visual inspection to determine the cause of the high benzene emissions and implementing repairs to reduce the level of emissions.

(4) Employing progressively more frequent sampling, analysis and meteorology (e.g., using shorter sampling periods for Methods 325A and 325B of Appendix A of 40 C.F.R. Part 63, or using active sampling techniques).

If, after completing the corrective action analysis and corrective actions such as those described in Paragraph 3(h), the Δc value for the next 14-Day sampling period for which the sampling start time begins after the completion of the corrective actions is greater than 9 μg/m^3 or if all corrective action measures identified require more than 45 Days to implement, the site must develop a corrective action plan that describes the corrective action(s) completed to date, additional measures that the site proposes to employ to reduce fenceline benzene concentrations below the action level, and a schedule for completion of these measures. The site must submit the corrective action plan to EPA within 60 Days after receiving the analytical results indicating that the Δc value for the 14-Day sampling period following the completion of the initial corrective action is greater than 9 μg/m3 or, if no initial corrective actions were identified, no later than 60 Days following the completion of the corrective action analysis required in Paragraph 3(h).

(i) The site may submit for review and approval a request to use an alternative test method as provided in 40 C.F.R. § 63.658(k).

Permit Numbers 1504A, PSDTX748M2, and N148M3

Attachment E

Alternative Method of Control (AMOC) Plan

AMOC No.: AMOC-32

Chevron Phillips Chemical Company, L.P.

Ethylene Plant Multi-Point Ground Flare (MPGF) System

Baytown, Harris County

Regulated Entity Number: RN103919817

A. This AMOC Plan Authorization shall apply at the Chevron Phillips Chemical Company, L.P. (CPCHEM) Cedar Bayou plant for ethylene production, located in Baytown, Harris County identified by Regulated Entity Number RN103919817 under Title 30 Texas Administrative Code Section 115.910 (30 TAC § 115.910) for the low-pressure (LP) and high-pressure (HP) stages of the multi-point ground flare (MPGF) system which is used during routine operations, planned maintenance, start-ups and shut-downs (MSS), and unplanned emergency and upset situations.

B. A copy of the AMOC application and the AMOC Plan provisions must be kept on-site or at a centralized location and made available at the request of personnel from the TCEQ or any pollution control agency with jurisdiction. The AMOC application is defined by the application received October 1, 2015, and supporting documentation submitted through January 13, 2017, as well as the subsequent revision application received December 18, 2024 and supporting documentation submitted through August 13, 2025.

C. This authorization is granted under § 115.910 for emissions sources regulated by 30 TAC Chapter 115, Subchapter B: General Volatile Organic Compound Sources, Division 2: Vent Gas Control and Subchapter H: Highly Reactive Volatile Organic Compounds, Division 1: Vent Gas Control. This AMOC shall apply in lieu of the requirements of 30 TAC §§ 115.122(a) and 115.722(d), as applicable.

   Compliance with this AMOC is independent of CPCHEM's obligation to comply with all other applicable requirements of 30 TAC Chapter 115, TCEQ permits and applicable state and federal law. The monitoring and testing requirements of 30 TAC §§ 115.125 and 115.725 shall continue to apply even though the flare is no longer subject to 30 TAC §§ 115.122(a) and 115.722(d).

   Compliance with the requirements of this plan does not ensure compliance with requirements of an applicable New Source Performance Standard, an applicable National Emission Standard for Hazardous Air Pollutants or an Alternative Means of Emission Limitation and does not constitute approval of alternative standards for these regulations.

D. In accordance with 30 TAC § 115.913(c), all representations submitted for this plan, as well as the provisions listed here, become conditions upon which this AMOC Plan is issued. It is unlawful to vary from the emission limits, control requirements, monitoring, testing, reporting or recordkeeping requirements of this Plan.

E. The single LP stage (Stage 0) and HP stages (Stages 1 – 17) of the MPGF system identified as EPN PK-905 in Permit Nos. 1504A, PSDTX48M1, and N148 is subject to this AMOC plan. The system collects and combusts hydrocarbon streams during routine operations, planned MSS activities, and emergencies. Operations of all stages will achieve a reduction in emissions at least equivalent to the reduction in emissions being controlled by a steam-assisted, air-assisted, or non-assisted flare complying with the requirements of §115.122(a), §115.722(d), or 40 CFR 60.18(b).

   1. The MPGF system LP stage (Stage 0) shall be designed and operated such that the following are met when regulated material is routed to that stage of burners:

i. The net heating value of the flare combustion zone (*NHVcz*) must be greater than or equal to 270 British thermal units per standard cubic foot (Btu/scf) demonstrated by continuously complying based on a 15-minute block average in accordance with § 63.670(e)(1).

ii. The actual flare tip exit velocity (V_{tip}) must comply with the limits of § 63.670(d).

2. The MPGF HP stages (Stages 1 -17) must be designed and operated such that the following are met when regulated material is routed to that stage of burners:

i. The *NHVcz* must be greater than or equal to 800 Btu/scf demonstrated by continuously complying based on a 15-minute block average in accordance with § 63.670(e)(2); or

ii. The combustion zone gas lower flammability limit (*LFLcz*) must be less than or equal to 6.5 percent by volume (6.5 $\%_{vol}$). The *LFLcz* compliance method is included as an alternative to the *NHVcz* compliance method due to the unique potential for high-hydrogen gas streams routed to the flare.

iii. No V_{tip} applies to the HP stages.

3. The owner or operator must demonstrate compliance with the *NHVcz* or *LFLcz* metric by continuously complying with a 15-minute block average in accordance with § 63.670(e). The operator must calculate and monitor for the *NHVcz* or *LFLcz* according to the following:

i. Calculation of the net heating value of vent gas (*NHVvg*) composition is determined by the concentration of individual components or the NHV in the flare vent gas using methods in 40 CFR §§ 63.670(j), 63.670(l) and Table 12 of 40 CFR 63 Subpart CC. Different monitoring methods may be used to determine vent gas composition for different gaseous streams that contribute to the flare vent gas.

$$NHV_{vg} = \sum_{i=1}^{n} x_i \, NHV_i$$

Where: *NHVvg* = Net heating value of flare vent gas, British thermal units per standard cubic foot (Btu/scf). *Flare vent gas* means all gas found just prior to the MPGF. This gas includes all flare waste gas (*i.e.,* gas from facility operations that is directed to a flare for the purpose of disposing of the gas), flare sweep gas, flare purge gas and flare supplemental gas, but does not include pilot gas.

i = Individual component in flare vent gas.

n = Number of components in flare vent gas.

x_i = Concentration of component *i* in flare vent gas, volume fraction.

NHV_i = Net heating value of component *i* determined as the heat of combustion where the net enthalpy per mole of offgas is based on combustion at 25 degrees Celsius (°C) and 1 atmosphere (or constant pressure) with water in the gaseous state from values published in the literature, and then the values converted to a volumetric basis using 20 °C for ‘‘standard temperature.’’ Table 1 (Appendix) summarizes component properties including net heating values.

ii. Calculation of *NHVcz*

a. The LP stage shall calculate *NHVcz* following §63.670(m).

b. For the 17 HP stages, *NHVvg* = *NHVcz*.

iii. Calculation of *LFLcz*

a. The owner or operator shall determine *LFLcz* from compositional analysis data by using the following equation:

$$LFL_{vg} = \frac{1}{\sum_{i=1}^{n}\left[\frac{\chi_i}{LFL_i}\right]} * 100\ \%$$

Where: *LFLvg* = Lower flammability limit of flare vent gas, volume percent (vol %)

n = Number of components in the vent gas.

i = Individual component in the vent gas.

χ_i = Concentration of component i in the vent gas, vol %.

LFLi = Lower flammability limit of component *i* as determined using values published by the U.S. Bureau of Mines (Zabetakis, 1965), vol %. All inerts, including nitrogen, are assumed to have an infinite LFL (*e.g., LFLN2* = ∞, so that c*N2*/ *LFLN2* = 0). LFL values for common flare vent gas components are provided in Table 1 (Appendix).

b. For the 17 HP stages, *LFLvg = LFLcz*.

4. The operator shall install, operate, calibrate and maintain monitoring systems per the following:

   i. A monitoring system capable of continuously measuring flare vent gas flow rate.

   ii. The operator shall install, operate, calibrate and maintain a monitoring system capable of continuously measuring temperature consistent with the applicable requirements in 30 TAC §115 for purposes of correcting flow rate to standard conditions. The monitor must meet the accuracy and calibration specifications annually.

   iii. The operator shall install, operate, calibrate and maintain a monitoring system capable of continuously measuring (*i.e.,* at least once every 15- minutes), calculating, and recording the individual component concentrations present in the flare vent gas or install, operate, calibrate and maintain a monitoring system capable of continuously measuring, calculating and recording *NHVvg* (in Btu/scf).

   iv. For each measurement produced by the monitoring system, the operator shall determine the 15-minute block average of all measurements made by the monitoring system within the 15-minute period in accordance with § 63.670(k), § 63.670(l), and § 63.670(e), as applicable.

   v. The operator must follow the calibration and maintenance procedures according to Table 2 (Appendix). Monitor downtime associated with maintenance periods, instrument adjustments or checks to maintain precision and accuracy. Zero and span adjustments may not exceed 5 percent of the time the flare is receiving regulated material. Calibration and maintenance procedures conducted when the flare is not receiving regulated material are excluded from the monitor downtime calculation.

F. Pilot Flame Requirements: The MPGF system shall be operated with a flame present at all times when regulated material is routed to that stage of burners and meet 40 CFR §63.670(b). Each stage of HP MPGF burners must be equipped with at least two pilots with a continuously lit pilot flame or flare flame. The pilot flame or flare flame must be continuously monitored by a thermocouple or any other equivalent device used to detect the presence of a flame. The time, date and duration of any complete loss of pilot flame or flare flame on any stage of MPGF burners must be recorded when regulated material is routed to that stage of burners. Each monitoring device must be maintained or replaced at a frequency in accordance with the manufacturer's specifications.

G. Visible Emission Requirements: When the flare is receiving regulated material, the MPGF system shall be operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours and meet 40 CFR § 63.670(c) and (h).

H. Monitor Requirements: The operator of a MPGF system shall install and operate pressure monitor(s) on the main flare header, as well as a valve position indicator monitoring system for each staging valve to ensure that the MPGF operates within the range of tested conditions or within the range of the manufacturer's specifications. The pressure monitor shall meet the requirements in Table 2 (Appendix).

Monitor downtime associated with maintenance periods, instrument adjustments or checks to maintain precision and accuracy and zero and span adjustments may not exceed 5 percent of the time the flare is receiving regulated material. Calibration and maintenance procedures conducted when the flare is not receiving regulated material are excluded from the monitor downtime calculation.

I. Closed Vent Capture Systems. Streams vented to the MPGF must be routed through a closed vent system that meets the requirements of NSR Permit No. 1504A.

J. Continuous Monitoring Requirements: Follow the specifications, calibration, and maintenance procedures according to the following:

1. General.

   i. At all times, all monitoring equipment must operate and be maintained in a manner consistent with 40 CFR §§ 60.11(d), 63.6(e)(1)(i), 63.671(a), and Table 13 of MACT CC with the TCEQ as the Administrator.

   ii. Any monitor downtime must comply with 40 CFR §§ 63.671(a)(4) and 63.671(c). The individual monitors and analyzers shall operate as required at least 95% of the time when any stage of the MPGF is operational, averaged over a rolling 12-month period. Periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments) are excluded from the monitor downtime calculation. Unless otherwise specified, for each measurement produced by the monitoring systems shall comply with 40 CFR §63.671(d) and Table 2 (Appendix).

2. Composition or Net Heating Values. Install, operate, calibrate, and maintain a monitoring system specified in (i) and may elect to supplement the monitoring as specified in (ii) or (iii).

   i. A calorimeter capable of continuously measuring, calculating, and recording the net heating value, *NHVvg*, present in the flare vent gas according to 40 CFR § 63.670(j)(3). The monitor shall meet the accuracy and calibration requirements of Table 13 of MACT CC.

   ii. A gas chromatograph or gas chromatograph / mass spectrograph system may be used to Determine *NHVvg* as specified in 40 CFR § 63.670(j)(1) or (2). Component properties determinations must follow 40 CFR § 63.670(l)(1) through (7) and Table 12 of MACT CC, as applicable. The system used to determine compositional analysis shall follow 40 CFR §§ 63.671(e) or 63.671(f), as applicable.

   iii. An optional hydrogen monitoring system may be used if capable of meeting 40 CFR §63.670(j)(4). The hydrogen analyzer must meet accuracy and calibration requirements of Table 13, MACT CC.

3. Flow Rates.

   i. Different flow monitoring methods may be used to measure different gaseous streams and steam provided that 40 CFR §63.670(i) is followed.

   ii. The measurement location must be selected following Table 13 of MACT CC.

   iii. All flow monitors shall meet the accuracy and calibration requirements of Table 13 of MACT CC.

4. Pilots.

   i. The pilot flame continuous monitoring must meet 40 CFR § 63.670(b).

   ii. Loss of pilot flame or flare flame is determined by and must meet 40 CFR §63.670(b) and records must follow 40 CFR § 63.655(i)(9)(i).

iii. A video camera that meets 40 CFR §63.670(h)(2) may be used to demonstrate compliance.

5. Pressure. Any pressure monitor used for flow measurements must meet the accuracy and calibration requirements of Table 13 of MACT CC.

6. Temperature. Any temperature monitor used for flow measurements must meet the accuracy and calibration requirements of Table 13 of MACT CC.

K. Recordkeeping Requirements: Records shall follow requirements in 40 CFR §63.655(i)(9), as applicable. All data must be recorded and maintained for a minimum of five years or for as long as applicable rule subpart(s) specify flare records should be kept, whichever is longer. Records must be maintained onsite and made available upon request by authorized representatives of the executive director, U.S. EPA, and any local air pollution control agency with jurisdiction.

L. Reporting Requirements:

1. The information specified in (b) and (c) below should be reported in the timeline specified by the applicable rules for which the MPGF will control emissions.

2. Owners or operators should include the following information in their initial Monitoring Plan:

i. Specify flare design as LP steam-assisted for Stage 0 and HP for Stages 1-17 pressure assisted MPGF.

ii. All visible emission readings, actual and maximum *Vtip* determinations, *NHVvg*, *NHVcz,* and/or *LFLcz* determinations, and flow rate measurements. For HP stages, exit velocity determinations do not need to be reported.

iii. All periods during the compliance determination when a complete loss of pilot flame on any stage of MPGF burners occurs.

iv. All periods during the compliance determination when the pressure monitor(s) on the main flare header show the MPGF burners operating outside the range of tested conditions or outside the range of the manufacturer's specifications.

v. All periods during the compliance determination when the staging valve position indicator monitoring system indicates a HP stage of the MPGF should not be in operation, but is; or when a stage of the MPGF should be in operation, but is not.

vi. All periods during the compliance determination when the staging valve position indicator monitoring system indicates an LP stage of the MPGF should be in operation, but is not.

3. The owner or operator shall notify the executive director of periods of excess emissions in their Title V Periodic Reports. These periods of excess emissions shall include:

i. Each 15-minute block during which there was at least one minute when regulated material was routed to the MPGF and a complete loss of pilot flame on a stage of burners occurred.

ii. Periods of visible emissions events that are time and date stamped and exceed more than 5 minutes in any 2 hour consecutive period.

iii. Each 15-minute block period for which an applicable combustion zone operating limit (*i.e., NHVcz* or *LFLcz*) is not met for the MPGF when regulated material is being combusted in the flare. Indicate the date and time for each period, the *NHVcz* and/or *LFLcz* operating parameter for the period, the type of monitoring system used to determine compliance with the operating parameters (*e.g.,* gas chromatograph or calorimeter), and the MPGF stages which were in use.

iv. Periods when the pressure monitor(s) on the main flare header show the HP MPGF burners are operating outside the range of tested conditions or outside the range of the manufacturer's specifications. Indicate the date and time for each period, the pressure measurement, the stage(s) and number of MPGF burners affected and the range of tested conditions or manufacturer's specifications.

v. Periods when the staging valve position indicator monitoring system indicates a stage of the HP MPGF should not be in operation but is; or when an HP stage of the MPGF should be in operation but is not. Indicate the date and time for each period, whether the stage was supposed to be open but was closed or vice versa and the stage(s) and number of MPGF burners affected.

M. Emission Determinations.
Calculations of hourly and annual emissions to determine compliance with the MAERT limitations shall be determined and recorded using the monitoring data collected pursuant to this AMOC Plan applying the best data of the parameters measured during each 15-minute block period and the appropriate emission factors based on the approach represented in the Permits. Annual emissions shall be calculated by the end of the current month for the previous rolling 12-month period.

APPENDIX Table 1 — Individual Component Properties

Component	Molecular Formula	MWi (lb/ lb mol)	NHVi (Btu/scf)	LFLi (volume %)
Acetylene	C2H2	26.04	1,404	2.5
Benzene	C6H6	78.11	3,591	1.3
1,2- Butadiene	C4H6	54.09	2,794	2.0
1,3- Butadiene	C4H6	54.09	2,690	2.0
iso-Butane	C4H10	58.12	2,957	1.8
n-Butane	C4H10	58.12	2,968	1.8
cis-Butene	C4H8	56.11	2,830	1.6
iso-Butene	C4H8	56.11	2,928	1.8
trans-Butene	C4H8	56.11	2,826	1.7
Carbon Dioxide	CO2	44.01	0	∞
Carbon Monoxide	CO	28.01	316	12.5
Cyclopropane	C3H6	42.08	2,185	2.4
Ethane	C2H6	30.07	1,595	3.0
Ethylene	C2H4	28.05	1,477	2.7
Hydrogen	H2	2.02	1,212	4.0
Hydrogen Sulfide	H2S	34.08	587	4.0
Methane	CH4	16.04	896	5.0
MethylAcetylene	C3H4	40.06	2,088	1.7
Nitrogen	N2	28.01	0	∞
Oxygen	O2	32.00	0	∞
Pentane+ (C5+)	C5H12	72.15	3,655	1.4
Propadiene	C3H4	40.06	2,066	2.16
Propane	C3H8	44.10	2,281	2.1
Propylene	C3H6	42.08	2,150	2.4
Water	H2O	18.02	0	∞

APPENDIX Table 2 — Accuracy and Calibration Requirements

Parameter	Accuracy requirements	Calibration requirements
Flare Vent Gas Flow Rate	±20 percent of flow rate at velocities ranging from 0.1 to 1 feet per second. ±5 percent of flow rate at velocities greater than 1 foot per second.	Performance evaluation biennially (every two years) and following any period of more than 24 hours throughout which the flow rate exceeded the maximum rated flow rate of the sensor, or the data recorder was off scale. Checks of all mechanical connections for leakage monthly. Visual inspections and checks of system operation every 3 months, unless the system has a redundant flow sensor. Select a representative measurement location where swirling flow or abnormal velocity distributions due to upstream and downstream disturbances at the point of measurement are minimized.
Pressure	±5 percent over the normal range measured or 0.12 kilopascals (0.5 inches of water column), whichever is greater.	Review pressure sensor readings at least once a week for straight-line (unchanging) pressure and perform corrective action to ensure proper pressure sensor operation if blockage is indicated. Performance evaluation annually and following any period of more than 24 hours throughout which the pressure exceeded the maximum rated pressure of the sensor, or the data recorder was off scale. Checks of all mechanical connections for leakage monthly. Visual inspection of all components for integrity, oxidation and galvanic corrosion every 3 months, unless the system has a redundant pressure sensor. Select a representative measurement location that minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.
Net Heating Value by Calorimeter	±2 percent of span	Calibration requirements should follow manufacturer's recommendations at a minimum. Temperature control (heated and/or cooled as necessary) the sampling system to ensure proper year-round operation. Where feasible, select a sampling location at least two equivalent diameters downstream from and 0.5 equivalent diameters upstream from the nearest disturbance. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in leakages, or other point at which a change in the pollutant concentration or emission rate occurs.
Net Heating Value by Gas Chromatograph	As specified in Performance Specification 9 of 40 CFR part 60 Appendix B.	Follow the procedure in Performance Specification 9 of 40 CFR Part 60 Appendix B, except that a single daily mid-level calibration check can be used, a triplicate mid-level check weekly, and the multi-point calibration can be conducted quarterly (rather than monthly), and the sampling line temperature must be maintained at a minimum temperature of 60 °C (rather than 120 °C).

APPENDIX 3 — Acronyms and Abbreviations

.
The AMOC uses multiple acronyms and terms, defined here (please note this list is not exhaustive):

AMEL	alternative means of emission limitation
AMOC	Alternate Method of Compliance or Control
Btu/scf	British thermal units per standard cubic foot
CAA	Clean Air Act
CBI	confidential business information
CFR	Code of Federal Regulations
CPCHEM	Chevron Phillips Chemical Company LP
EPA	Environmental Protection Agency
EPN	Emission Point Number
Eqn	equation
HAP	hazardous air pollutants
HP	high pressure
LFL	lower flammability limit
LFLcz	lower flammability limit of combustion zone gas
LFLvg	lower flammability limit of flare vent gas
MPGF	multi-point ground flares
MSS	planned maintenance, start-ups and shut-downs
NESHAP	National Emission Standards for Hazardous Air Pollutants
NHV	net heating value
NHVcz	net heating value of combustion zone gas
NHVvg	net heating value of flare vent gas
NSPS	New Source Performance Standards
OAQPS	Office of Air Quality Planning and Standards
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
scf	standard cubic feet
VOC	volatile organic compounds
Vtip	actual flare tip velocity

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 1504A, PSDTX748M2, and N148M3

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-01A	Cracking Furnace BA-101	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57
1592-01B	Cracking Furnace BA-102	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-02A	Cracking Furnace BA-103	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57
1592-02B	Cracking Furnace BA-104	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-03A	Cracking Furnace BA-105	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57
1592-03B	Cracking Furnace BA-106	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-04A	Cracking Furnace BA-107	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57
1592-04B	Cracking Furnace BA-108	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-05A	Cracking Furnace BA-109	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57
1592-05B	Cracking Furnace BA-110	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-06A	Cracking Furnace BA-111	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57
1592-06B	Cracking Furnace BA-112	CO	20.49	33.76
		CO (5)	73.03	36.52
		NOx	24.88	20.50
		PM	1.85	6.11
		PM_{10}	1.85	6.11
		$PM_{2.5}$	1.85	6.11
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.15	0.48
		VOC	1.34	4.42
		NH_3	1.08	3.57

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-07	Cracking Furnace BA-113	CO	18.76	32.19
		CO (5)	73.03	36.52
		NOx	22.78	19.55
		PM	1.70	5.83
		PM_{10}	1.70	5.83
		$PM_{2.5}$	1.70	5.83
		PM (5)	3.50	1.75
		PM_{10} (5)	3.50	1.75
		$PM_{2.5}$ (5)	3.50	1.75
		SO_2	0.13	0.46
		VOC	1.23	4.22
		NH_3	0.99	3.40
1592-38	Cracking Furnace BA-117	CO	18.43	36.03
		CO (5)	73.03	54.77
		NOx	13.43	52.51
		PM	1.67	6.52
		PM_{10}	1.67	6.52
		$PM_{2.5}$	1.67	6.52
		PM (5)	3.50	2.63
		PM_{10} (5)	3.50	2.63
		$PM_{2.5}$ (5)	3.50	2.63
		SO_2	0.13	0.51
		VOC	1.21	4.72

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-10	Boilers BF-801A and BF-801B	CO	115.73	264.87
		NOx	118.04	280.63
		PM	53.41	154.86
		PM_{10}	53.41	154.86
		$PM_{2.5}$	53.41	154.86
		SO_2	336.52	975.78
		VOC	7.58	17.34
	Boilers BF-801A and BF-801B MSS	NOx	240.00	-
		CO	259.23	-
1592-11	Boiler BF-801C	CO	57.86	132.44
		NOx	59.02	140.31
		PM	26.71	77.43
		PM_{10}	26.71	77.43
		$PM_{2.5}$	26.71	77.43
		SO_2	168.29	488.02
		VOC	3.79	8.67
	Boiler BF-801C MSS	NOx	120.00	-
		CO	129.61	-
1592-12	Furnace BA-651	CO	4.18	18.31
		NOx	3.05	8.00
		PM	0.38	1.66
		PM_{10}	0.38	1.66
		$PM_{2.5}$	0.38	1.66
		SO_2	0.03	0.13
		VOC	0.27	1.20

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-13	Furnace BA-401	CO	2.68	1.54
		NOx	3.25	2.25
		PM	0.24	0.14
		PM_{10}	0.24	0.14
		$PM_{2.5}$	0.24	0.14
		SO_2	0.02	0.01
		VOC	0.18	0.10
1592-16	Flare CB-701 – Routine Emissions	CO	2098.94	-
		NOx	407.44	-
		VOC	3145.35	-
		SO_2	2.22	-
		H_2S	0.02	-
	MSS Emissions Maintenance	CO	2151.16	-
		NOx	436.68	-
		VOC	3099.79	-
		SO_2	66.33	-
		H_2S	0.70	-
	Routine and MSS Annual Emissions Cap	CO	-	107.68
		NOx	-	24.83
		VOC	-	70.38
		SO_2	-	0.22
		H_2S	-	0.01
1592-18	Vent FG-401 Maintenance	CO	35.00	2.10
		NOx	0.08	0.01
		PM	0.01	0.01
		PM_{10}	0.01	0.01
		$PM_{2.5}$	0.01	0.01
		VOC	11.70	0.70
		SO_2	0.34	0.02

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-18A	Vent FG-652 / 651 Maintenance	CO	160.00	15.36
		NOx	0.08	0.01
		PM	0.01	0.01
		PM_{10}	0.01	0.01
		$PM_{2.5}$	0.01	0.01
		VOC	11.70	1.12
		SO_2	0.34	0.03
1592-19	HAD Tank FB-701	VOC	0.20	0.08
1592-20	Wastewater Tank FB-702	VOC	2.17	0.59
1592-21	Methanol Tank FB-402	VOC	26.77	0.18
1592-22	HPG Tank FB-704A	VOC	0.33	0.66
1592-22A	HPG/RPG Tank FB-704B	VOC	1.04	2.75
1592-24	HPFO Tank FB-705	VOC	11.47	5.73
1592-25	LPFO Tank FB-712	VOC	4.54	2.01
1592-26	Spent Caustic Tank FB-706	VOC	0.13	0.29
1592-27	Heavy Slop Oil Tank FB-707	VOC	3.88	0.23
1592-28	HAD/Wash Oil Tank FB-710	VOC	3.77	0.26
1592-31	Process Area Fugitives (4)	VOC	14.12	61.52
1592-32	Wastewater Tank FB-862	VOC	0.65	0.72
1592-33A	WW/Slop Oil Emulsion Tank FB-892A	VOC	19.78	0.11
L1592-33A	Loading Slop Oil Tank FB-892A	VOC	4.65	0.15
1592-33B	Slop Oil Tank FB-892B	VOC	0.52	0.41
1592-33C	Slop Oil Tank FB-892C	VOC	0.52	0.41
1592-36A	Tank Compressor Lube Oil	VOC	0.13	0.55
1592-36B	Tank Compressor Lube Oil	VOC	0.43	1.88

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-40	Flare CB-710 – Routine Emissions	VOC	31.56	-
		NOx	6.83	-
		CO	35.13	-
		SO_2	0.05	-
	MSS Emissions	VOC	133.82	-
		NOx	19.29	-
		CO	99.36	-
	Routine and MSS Annual Emissions Cap	VOC	-	2.59
		NOx	-	2.91
		CO	-	14.9
		SO_2	-	0.16
1592-41	Cooling Tower EF-751	VOC	6.17	16.83
		PM	3.68	8.05
		PM_{10}	3.68	8.05
		$PM_{2.5}$	1.08	3.30
L-103	Loading Trucks/Rail-103	VOC	2.01	0.95
L-1592-24	Loading Trucks FB-705	VOC	7.46	4.66
L-1592-25	Loading Trucks FB-712	VOC	3.18	3.70
F-160	Utilities Area Fugitives (4)	VOC	0.31	1.34
90	Tank (HAD)-103	VOC	0.08	0.08
149	Tank (RPG) FB-703	VOC	1.81	3.83
1592-48	Wastewater Tank FB-918	VOC	1.85	0.53
1592-49	Wastewater Tank FB-930	VOC	0.69	0.51
1592-50	Wastewater Tank FB-204	VOC	8.08	0.18
1592-WWTP	WWTP Equipment	VOC	3.63	4.50

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-56	Firewater Pump P-111B	VOC	0.26	0.12
		NOx	3.60	1.58
		CO	1.50	0.66
		SO_2	2.00	0.87
		PM	0.14	0.06
		PM_{10}	0.14	0.06
		$PM_{2.5}$	0.14	0.06
1592-57	Firewater Pump GA-809	VOC	0.63	0.28
		NOx	7.91	3.46
		CO	1.70	0.75
		SO_2	0.52	0.23
		PM	0.56	0.25
		PM_{10}	0.56	0.25
		$PM_{2.5}$	0.56	0.25
1592-58	Electric Generator GE-800	VOC	1.06	0.47
		NOx	13.33	5.84
		CO	2.87	1.26
		SO_2	0.88	0.39
		PM	0.95	0.41
		PM_{10}	0.95	0.41
		$PM_{2.5}$	0.95	0.41
1592-59	Firewater Pump PU-752	VOC	0.48	0.21
		NOx	18.00	7.88
		CO	4.13	1.81
		SO_2	0.30	0.13
		PM	0.53	0.23
		PM_{10}	0.53	0.23
		$PM_{2.5}$	0.53	0.23

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-60	Stormwater Pump GA-920A	VOC	0.57	0.25
		NOx	7.13	3.12
		CO	1.54	0.67
		SO_2	0.47	0.21
		PM	0.51	0.22
		PM_{10}	0.51	0.22
		$PM_{2.5}$	0.51	0.22
1592-61	Stormwater Pump GA-920B	VOC	0.57	0.25
		NOx	7.13	3.12
		CO	1.54	0.67
		SO_2	0.47	0.21
		PM	0.51	0.22
		PM_{10}	0.51	0.22
		$PM_{2.5}$	0.51	0.22
1592-62	Stormwater Pump GA-912A	VOC	0.57	0.25
		NOx	7.13	3.12
		CO	1.54	0.67
		SO_2	0.47	0.21
		PM	0.51	0.22
		PM_{10}	0.51	0.22
		$PM_{2.5}$	0.51	0.22

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
1592-63	Stormwater Pump GA-912B	VOC	0.57	0.25
		NOx	7.13	3.12
		CO	1.54	0.67
		SO_2	0.47	0.21
		PM	0.51	0.22
		PM_{10}	0.51	0.22
		$PM_{2.5}$	0.51	0.22
1592-64	Lube Oil Tank	VOC	0.06	0.01
1592-65	GA912 DTK Diesel Tank	VOC	0.05	0.01
1592-66	FB-920 Diesel Tank	VOC	0.05	0.01
1592-67	GE800DTK Diesel Tank	VOC	0.05	0.01
1592-68	GE809DTK Diesel Tank	VOC	0.01	0.01
1592-69	VE-752 Diesel Tank	VOC	0.04	0.01
1592-70	Tank No. FB-450	VOC	1.94	0.01
1592-71	Spent Caustic Sump	VOC	1.48	0.17
1592-72	Butadiene Feedstock Pump	VOC	0.02	0.02
1592ANAL	Analyzer Vents	VOC	0.06	0.25
F-MSSEU	MSS Fugitive Emissions	VOC	5.00	0.75
		PM	0.02	0.01
		PM_{10}	0.02	0.01
		$PM_{2.5}$	0.02	0.01

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
H-101	Cracking Furnace H-101	CO	146.22	-
		NOx	12.50	-
		NOx (6)	24.38	-
		PM	3.73	-
		PM_{10}	3.73	-
		$PM_{2.5}$	3.73	-
		SO_2	2.80	-
		VOC	2.70	-
		NH_3	2.34	-
H-102	Cracking Furnace H-102	CO	146.22	-
		NOx	12.50	-
		NOx (6)	24.38	-
		PM	3.73	-
		PM_{10}	3.73	-
		$PM_{2.5}$	3.73	-
		SO_2	2.80	-
		VOC	2.70	-
		NH_3	2.34	-
H-103	Cracking Furnace H-103	CO	146.22	-
		NOx	12.50	-
		NOx (6)	24.38	-
		PM	3.73	-
		PM_{10}	3.73	-
		$PM_{2.5}$	3.73	-
		SO_2	2.80	-
		VOC	2.70	-
		NH_3	2.34	-

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
H-104	Cracking Furnace H-104	CO	146.22	-
		NOx	12.50	-
		NOx (6)	24.38	-
		PM	3.73	-
		PM_{10}	3.73	-
		$PM_{2.5}$	3.73	-
		SO_2	2.80	-
		VOC	2.70	-
		NH_3	2.34	-
H-105	Cracking Furnace H-105	CO	146.22	-
		NOx	12.50	-
		NOx (6)	24.38	-
		PM	3.73	-
		PM_{10}	3.73	-
		$PM_{2.5}$	3.73	-
		SO_2	2.80	-
		VOC	2.70	-
		NH_3	2.34	-
H-106	Cracking Furnace H-106	CO	146.22	-
		NOx	12.50	-
		NOx (6)	24.38	-
		PM	3.73	-
		PM_{10}	3.73	-
		$PM_{2.5}$	3.73	-
		SO_2	2.80	-
		VOC	2.70	-
		NH_3	2.34	-

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
H-107	Cracking Furnace H-107	CO	146.22	-
		NOx	12.50	-
		NOx (6)	24.38	-
		PM	3.73	-
		PM_{10}	3.73	-
		$PM_{2.5}$	3.73	-
		SO_2	2.80	-
		VOC	2.70	-
		NH_3	2.34	-
H-108	Cracking Furnace H-108	CO	146.22	-
		NOx	12.50	-
		NOx (6)	24.38	-
		PM	3.73	-
		PM_{10}	3.73	-
		$PM_{2.5}$	3.73	-
		SO_2	2.80	-
		VOC	2.70	-
		NH_3	2.34	-
H-109	Cracking Furnace H-109	CO	27.42	-
		CO (6)	219.34	-
		NOx	11.25	-
		NOx (6)	33.75	-
		PM	5.59	-
		PM_{10}	5.59	-
		$PM_{2.5}$	5.59	-
		SO_2	4.20	-
		VOC	4.04	-
		NH_3	4.76	-

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
PK-830	VHP Boiler PK-830	CO	153.54	-
		NOx	13.13	-
		NOx (6)	34.13	-
		PM	3.91	-
		PM_{10}	3.91	-
		$PM_{2.5}$	3.91	-
		SO_2	2.94	-
		VOC	3.18	-
		NH_3	2.45	-
Total emissions for the following EPNs:				
H-101 H-102 H-103 H-104 H-105 H-106 H-107 H-108 H-109 PK-830	Cracking Furnaces and HP Boiler Annual Emission Cap	CO	-	664.76
		NOx	-	209.04
		SO_2	-	29.60
		PM	-	89.49
		PM_{10}	-	89.49
		$PM_{2.5}$	-	89.49
		VOC	-	64.99
		NH_3	-	102.56

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
PK-840	Cooling Tower EU 1594	VOC	7.77	8.35
		PM	2.31	5.07
		PM_{10}	2.31	5.07
		$PM_{2.5}$	0.69	2.08
PK-905	EU 1594 Flare PK-905 Routine and Maintenance	VOC	1505.84	-
		NOx	405.69	-
		CO	1616.00	-
		SO_2	12.83	-
		H_2S	0.14	-
PK-905	EU 1594 Flare PK-905 Startup/Shutdown	VOC	6,428.09	-
		NOx	2,497.52	-
		CO	9,946.64	-
		SO_2	12.83	-
		H_2S	0.14	-
PK-905	EU 1594 Flare PK-905 Annual Emissions Cap	VOC	-	157.42
		NOx	-	83.69
		CO	-	354.67
		SO_2	-	17.23
		H_2S	-	0.19

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
PK-906	EU 1594 VDU	VOC	7.14	0.88
		NOx	4.32	3.13
		CO	8.64	6.25
		SO_2	0.08	0.06
		PM	0.21	0.16
		PM_{10}	0.21	0.16
		$PM_{2.5}$	0.21	0.16
F-1594	EU 1594 Process Area Fugitives (4)	VOC	6.11	26.76
		NH3	0.12	0.53
F-1595	PU 1595 Process Area Fugitives (4)	VOC	0.41	1.79
WWT-1594	Wastewater Treatment	VOC	3.86	1.11
TK-937	EU 1594 Stormwater Tank	VOC	4.19	2.68
FMSSEU1594	EU 1594 Equipment Opening	VOC	125.50	1.50
		PM	0.02	0.01
		PM_{10}	0.02	0.01
		$PM_{2.5}$	0.02	0.01
FMSSPU1595	PU 1595 Equipment Opening	VOC	124.50	1.00
CAT-1595	PU 1595 Catalyst Handling	PM	0.09	0.01
		PM_{10}	0.04	0.01
		$PM_{2.5}$	0.04	0.01

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (7)
PK-871 PK-872 PK-873	EU 1594 Emergency Generators	VOC	4.68	0.12
		NOx	55.13	1.43
		CO	33.41	0.87
		SO_2	0.03	0.01
		PM	1.91	0.05
		PM_{10}	1.91	0.05
		$PM_{2.5}$	1.91	0.05
EMGEN-1	Emergency Engine	VOC	4.41	0.11
		NOx	4.41	0.11
		CO	3.86	0.10
		SO_2	0.01	0.01
		PM	0.22	0.01
		PM_{10}	0.22	0.01
		$PM_{2.5}$	0.22	0.01
TK-871 TK-872 TK-873	Diesel Tanks	VOC	0.59	0.01

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO - carbon monoxide
VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - Particulate matter equal to or less than 2.5 microns in diameter
H_2S - hydrogen sulfide
(4) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(5) Decoking emissions (maintenance) for furnaces BA-101 through BA-113 and BA-117.
(6) Planned startup and shutdown, and non-routine operation as defined in Special Condition No. 10.D for Furnaces H-101 through H-109 and Boiler PK-830.
(7) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period.

Date: TBD

Preliminary Determination Summary

Permit Numbers 1504A, PSDTX748M2, and N148M3

I. Applicant
Chevron Phillips Chemical Company LP
9500 Interstate 10 East
Baytown, TX 77521-8155

II. Project Location
Cedar Bayou Plant
9500 Interstate 10 E
Harris County
Baytown, Texas 77521

III. Project Description
Chevron Phillips Chemical Company LP (CPChem) owns and operates an olefins and polyolefins complex at the Cedar Bayou Plant located in Baytown, Harris County, Texas. The facility includes ethylene cracking units, polyethylene units, and normal and polyalphaolefin manufacturing units. CPChem completed the construction and startup of an ethylene expansion project where a new Ethylene Unit, EU-1594, was added to the Cedar Bayou Plant's existing ethylene production capabilities. The expansion was originally authorized by TCEQ NSR Project No. 172655 in 2013 and a subsequent NSR Project No. 295451 in 2020. The expansion included eight cracking furnaces, one high pressure boiler, a flare, a vapor destruction unit (VDU), a cooling tower, a wastewater treatment unit, a storm water tank, three diesel tanks, three emergency generators, and piping components).

On December 3, 2024, CPChem submitted this as-built amendment application to update emissions for EU 1594 Flare (EPN PK-905) and annual NOx emission rates for Cracking Furnaces and HP Boiler Annual Emission Cap.

Planned maintenance, startup, and shutdown (MSS) emissions are authorized in this project and updates to both routine and MSS scenarios and flows routed to flare are included in this as-built permit amendment project. The applicant did not propose to incorporate any PBRs through this project action.

IV. Emissions

Air Contaminant	Proposed Allowable Emission Rates (tpy)
PM	449.85
PM_{10}	449.85
$PM_{2.5}$	442.11
VOC	547.98
NO_X	1105.65
CO	2593.46
SO_2	1520.42
H_2S	0.20
GHG (CO_2e)	1,453,852

V. Federal Applicability

The following chart illustrates the annual project emissions for each pollutant and whether this pollutant triggers PSD or Nonattainment (NA) review.

Pollutant	Project Emissions (tpy)	Major Mod Trigger (tpy)	NA Triggered Y/N	PSD Triggered Y/N
VOC	42.42	25 for NA 40 for PSD	Y	N/A
NO_x	41.62	25 for NA 40 for PSD	Y	Y
SO_2	38.95	40	N/A	N
CO	100.40	100	N/A	Y
PM	0	25	N/A	N
PM_{10}	0	15	N/A	N
$PM_{2.5}$	0	10	N/A	N
H_2S	0.13	7	N/A	N
GHG (CO_2e)	47,940	10	N/A	N

This as-built amendment proposes emission changes to only two sources: Cracking Furnaces and HP Boiler Annual Emission Cap and U 1594 Flare PK-905. A retrospective NNSR and PSD applicability analysis has been completed for this permit amendment application which reflects an update to the analysis that was completed in support of the initial permit issuance on August 6, 2013. See NNSR and PSD section for further details on federal applicability.

These pollutants previously triggered PSD and/or nonattainment in the last as-built amendment Project No. 295451. During the retrospective review, additional potential-to-emit (PTE, or MAERT limits) emission increases were calculated and compared to their respective major modification thresholds. Note these additional PTE increases should have been part of the original expansion project and could have contributed to the previous project emissions increase for the NNSR/PSD applicability review purposes. In the case that the additional PTE/MAERT emission increase exceeds the applicable major modification threshold, a new major modification to the current federal NNSR/PSD permit will be triggered. See additional information in the Nonattainment and PSD review applicability section.

For these pollutants where a federal NSR permit or major modification was not issued previously in Project No. 172655 or subsequent Project No. 295451, a retrospective review was conducted following the regular baseline actual emissions (BAE) to potential to emit (PTE) approach. They did not still trigger PSD major modifications in the present project.

Nonattainment review (NA) applicability:

The CPChem Cedar Bayou Plant is located in Baytown, Harris County, which has been designated as a severe nonattainment area under the 2008 8-hour ozone standard. The construction of Ethyne Unit (EU-1594) was originally authorized in Project No. 172655 and subsequently amended via an as-built amendment Project No. 295451 (retrospective to Project No. 172655). The present project serves as a second as-amendment to authorize additional changes to EU-1594 that was approved in Project No. 295451. A summary of permit history regarding the federal NSR applicability is as follows:

Project No.	Completion Date	Effective NA Designation	Description
172655	2013-08-06	Severe	(1) Construction of EU-1594 was initially authorized. (2) Nonattainment review was triggered by VOC and NOx. (3) PSD review was triggered by CO, NO2 and PM2.5.
295451	2020-06-12	Serious	(1) First as-built. Retrospective review was conducted. (2) Nonattainment review was triggered by VOC and NOx. (3) PSD review was triggered by NOx, CO, PM, PM10, PM2.5, and GHGs. (4) Note the amendment was not considered a new major modification since the original project (No. 172655) already triggered nonattainment and PSD.
385401	Currently pending	Severe	(1) Second as-built amendment. Retrospective review is required. (2) A new major modification to nonattainment is being triggered by VOC and NOx. (3) A new major modification to PSD is being triggered by NO2 and CO.

As shown in the table above, both VOC and NOx triggered nonattainment review in the previous as-built amendment (Project No. 295451). Since the present project serves as a second as-amendment, it shall be evaluated in a retrospective manner. This project proposes a PTE increase of 42.42 tpy VOC and a PTE increase of 41.62 tpy NOx, which both exceed the 5 tpy netting threshold under the severe designation. CPChem has chosen to forgo the contemporaneous netting analysis for VOC and NOx, and apply nonattainment directly to the project.

The project emission increases will be offset in accordance with 30 TAC §116.150(d)(3) at a ratio of 1.3 to 1. The VOC and NOx project increases and emission offsets for this project are detailed in the table below.

Pollutant	VOC	NOx
Current Project Emission Increase (tpy)	42.42	41.62
Current NNSR Offsets Required (tpy, 1.3:1)	55.1	54.1
Existing Offsets specified in Special Conditions (tpy, see SC Nos. 7-8)	256.5	300.4
Total New NNSR Offsets Required after the present Project (tpy)	311.6	354.5

Therefore, updated offset requirements of 311.6 tpy VOC and 354.5 tpy NOx will be incorporated in permit Special Conditions 7 and 8. The existing nonattainment permit number N148M2 will be modified to N148M3 upon the issuance of this project.

PSD review applicability:

The CPChem Cedar Bayou Plant is located in Harris County which has been designated as a severe nonattainment area for ozone. Therefore, PSD review is not applicable for ozone precursor VOC.

The CPChem Cedar Bayou Plant is an existing major source with respect to the PSD program. Project emission increases of NOx and CO exceed their PSD significance thresholds of 40 tpy and 100 tpy, respectively. Therefore, contemporaneous netting is required. CPChem has chosen to forgo the contemporaneous netting analysis for CO and NOx, and proceed with PSD review. Therefore, PSD review applies to NOx and CO.

Accordingly, the existing PSD permit number PSDTX748M1 will be modified to PSDTX748M2 upon the issuance of this project.

Project emission increases for SO2 and H2S are less than their PSD significant thresholds of 40 tpy and 10 tpy, respectively. Therefore, PSD review does not apply to SO2 or H2S.

During the original authorization of EU-1594 via TCEQ Project No. 172655 in 2013, EPA was maintaining the GHG permitting authority and a GHG Permit No. PSD-TX-748-GHG was issued by EPA. In 2017, the EPA-issued GHG permit number was assigned Permit No. GHGPSDTX9 in accordance with the TCEQ's numbering system via TCEQ NSR Project No. 253701. GHGs triggered PSD review in the subsequent as-built amendment (Project No. 295451) in 2020. In the present project, the project emission increase or PTE increase of 47,940 tpy CO2e is below the GHG PSD significance thresholds of 75,000 tpy. Therefore, GHG does not trigger PSD review in the present project. However, CPChem proposes volunteer updates to GHG Permit No. GHGPSDTX9 with this application.

VI. Control Technology Review

All proposed modified sources in this application are required to meet The Lowest Achievable Emission Rate (LAER) for VOC and NOx, and state minor NSR BACT for other criteria pollutants including CO that has triggered PSD major modification. The Lowest Achievable Emission Rate (LAER) is the most stringent emissions limitation achieved in practice or in an approved state implementation plan of any state for such class or source category. LAER takes technical feasibility into account, but not economic reasonableness. The applicant submitted RACT/BACT/LAER Clearinghouse (RBLC) database search summaries for the pollutants that triggered LAER review, NOx and VOC.

State BACT pursuant to 30 TAC 116.111(a)(2)(C) is required to be met for other pollutants and is addressed in the table below as well.

Source Name	EPN	Best Available Control Technology Description
Cracking Furnaces and HP Boiler Annual Emission Cap	H-101, H-102, H-103, H-104, H-105, H-106, H-107, H-108, H-109, PK830	The existing annual emissions cap consists of nine (9) Cracking Furnaces H-101 through H-109, and one (1) Boiler PK-830. Only annual NOx emissions were updated through the proposed project. There is no change to short term NOx emissions or any other pollutant under the cap. BACT and LAER for olefins cracking furnace NOx emissions control is well established as low-NOx burner technology used in conjunction with selective catalytic reduction (SCR). CPChem proposes controls using low NOx burner technology and SCR. Note that the RACT/BACT/LAER Clearinghouse (RBLC) search results reflect NOx controls ranging from 0.006

Source Name	EPN	Best Available Control Technology Description
		– 0.007 lbs/MMBtu. However, upon review of available technical permit files associated with the RBLC search results, it was determined that the facility types associated with the 0.006-0.007 lbs/MMbtu NOx controls represent non-cracking furnaces. In addition, CPChem justified that its cracking furnaces operate at extreme high radiant section temperatures where NOx formation occurs and these extreme temperatures require specialized metallurgy with high chrome content which serves as is a masking agent to SCR catalyst. Further, a 0.009 lb/MMBtu NOx factor has been identified as LAER during RBLC search for a similar category of source as in LA-0389, Shintech Louisiana LLC (2024) and LA-0389 Shintech Louisiana LLC (2022). However, CPChem justified that the fundamental difference affecting NOx emissions between the Shintech EDC cracking furnaces and the CPChem Ethylene cracking furnaces is the firebox temperature. Thermal NOx production in a firebox during combustion is a function of firebox temperature. As the firebox temperature increases, NOx production from the burners also increases. EDC furnaces operate in the range of 1400˚ F in the firebox and produce relatively lower NOX compared to ethylene cracking furnaces that operate in the range of 2200 ˚F producing significantly higher NOx. The increase in the annual NOx emission rate is due to a correction to the previous representation of Furnaces H-101 through H-108. There is no modification to any unit under the cap or any increase in other pollutant. Due to these technical reasons, the proposed 0.01 lbs NOx/MMBtu in this application satisfies LAER for cracking furnaces. The PK830 Boiler is included in the annual emissions cap with the cracking furnaces. The PK830 Boiler is also equipped with low-NOx burners and SCR to achieve an NOx emission limit of 0.01 lbs/MMBtu on an annual basis. No change or correction is being made to the boiler in the present project. LAER was previously evaluated and deemed to be acceptable in Project No. 295451.
EU 1594 Flare PK-905 Annual Emissions Cap	PK-905	The EU-1594 Flare (EPN PK-905) is a multi-point ground flare (MPGF) that has a low-pressure steam assisted stage and 17 high pressure stages that are unassisted. The low-pressure and steam-assisted stage is always in service controlling ethylene production and some maintenance, startup, and shutdown (MSS) activities. The remaining high-capacity stage rows contain high pressure burners that are unassisted to handle high pressure discharges due to emergencies, start-up and shutdown operations, and other large volume maintenance clearing. The flare includes a totalizing flow meter with temperature and pressure compensation, an online analyzer to measure speciated hydrocarbons in the inlet stream at least once every

Source Name	EPN	Best Available Control Technology Description
		15 minutes, multiple stage rows with several high capacity burners on each row, a staging control system to maintain pressure in the flare, continuous pilot ignitors and pilot detection systems, steam assist to minimize smoking conditions, and ground flare fences to control air distribution, reduce noise, and minimize thermal radiation. In addition, net heating value in the composition zone (NHVcz) shall be monitored to meet 40 CFR Subpart CC requirements as specified in the attached AMOC 32. The first stage is equipped with low pressure burners that are steam assisted. The seventeen remaining stages contain high pressure burners that are unassisted. The RBLC search for flare controls indicates that good combustion, good operational maintenance practices, and compliance with 40 CFR §60.18 meets LAER for NOx. This flare is subject to additional monitoring requirements specified in 40 CFR Subpart CC. VOC: The flare shall achieve a VOC compound destruction efficiency of 99% for compounds with up to three carbons, and 98% for compounds with four or more carbon atoms. The claimed 98%/99% DREs are conservative for MPGFs. The proposed operating practices satisfy LAER and are consistent with recent TCEQ LAER determinations for chemical plant flares. NOx: Emissions of thermal NOx from the flare are the result of high combustion temperatures and elemental nitrogen in the atmosphere. Vapor streams will not contain any fuel bound nitrogen, therefore no fuel bound NOx emissions will be produced. CPChem proposes operating practices that include minimizing the amount of flaring to the extent possible to satisfy LAER for emissions of NOx. According to the associated AMOC No. 32 as specified in Attachment E, this flare will be monitored and meet 40 CFR Subpart CC requirements including the following parameters: net heating value (NHV) in the composition zone and vent gas, flare tip velocity, flow rate, pilot flames, pressure, visible emissions, lower flammability limit, etc. Monitoring of these parameters is more stringent than 40 CFR §60.18 requirements. Therefore, the flares achieve LAER for VOC and NOx. CO: CO emissions are based on the TCEQ approved emission factors. CPChem proposes to minimize formation of CO emissions through proper design and minimizing the amount of flaring to the extent possible to meet BACT requirements. SO2: CPChem proposes the use of low sulfur pilot gas and proper design and operation to satisfy BACT requirements for SO2 emissions.

VII. Air Quality Analysis

The air quality analysis (AQA) is acceptable for all review types and pollutants. The results are summarized below.

This is an as-built amendment to NSR Projects 172655 and 295451. This analysis updates the permit application representations and emission rates to reflect updates to the low profile flare (EPN PK-905) and cracking furnaces (EPNs H-101 to H-108). The applicant evaluated the project sources the same as the original submittal but incorporated the as-built changes associated with this project.

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results for annual NO_2 indicate that the project is below the respective de minimis concentrations and no further analysis is required.

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (µg/m^3)

Pollutant	Averaging Time	GLCmax* (µg/m^3)	De Minimis (µg/m^3)
NO_2	Annual	0.74	1

* Ground level maximum concentration

The GLCmax represents the maximum predicted concentration over five years of meteorological data.

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with EPA's Guideline on Air Quality Models. Specifically, the applicant used a Tier 1 demonstration tool developed by EPA referred to as Modeled Emission Rates for Precursors (MERPs, https://www.epa.gov/sites/default/files/2020-09/documents/epa-454_r-19-003.pdf). The basic idea behind MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 500 tpy Harris County source, the applicant estimated an annual secondary $PM_{2.5}$ concentration of 0.0019 µg/m^3. As there are no direct $PM_{2.5}$ emission rate increases with this project and the annual secondary $PM_{2.5}$ concentrations have decreased from Project 295451, no further analysis is required.

The project site is located in the Houston-Galveston-Brazoria ozone nonattainment area. Therefore, an ambient ozone impacts analysis is not required.

B. Air Quality Monitoring

The De Minimis analysis modeling result indicates that annual NO_2 is below the respective monitoring significance level.

Table 2. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Significance ($\mu g/m^3$)
NO_2	Annual	0.74	14

The GLCmax represents the maximum predicted concentration over five years of meteorological data.

C. National Ambient Air Quality Standard (NAAQS) Analysis

The De Minimis analysis modeling results indicate that NO_2 is below the respective de minimis concentrations and no further analysis is required.

D. Increment Analysis

The De Minimis analysis modeling results indicate that NO_2 is below the respective de minimis concentration and no further analysis is required.

E. Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soil and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 Texas Administrative Code Chapter 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Caney Creek Wilderness, is located approximately 509 kilometers (km) from the proposed site.

The predicted concentrations of NO_2 for the annual averaging time are all less than de minimis levels at the fence line in the direction the Caney Creek Wilderness Class I area. The Caney Creek Wilderness Class I area is an additional 509 km from the location where the predicted concentration of NO_2 for the annual averaging time are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Caney Creek Wilderness Class I area.

F. Minor Source NSR and Air Toxics Analysis

Table 3. Generic Modeling Results

Source ID	Annual GLCmax ($\mu g/m^3$ per tpy)	Annual Vegetation GLCmax ($\mu g/m^3$ per tpy)
CT	0.04	0.01
F1594	0.06	0.02

Source ID	Annual GLCmax (µg/m^3 per tpy)	Annual Vegetation GLCmax (µg/m^3 per tpy)
PK_830	0.01	-
PK_905	0.01	0.01
PK_905SU	0.01	0.01
PK_906	0.02	-
S_920CC	0.05	0.01
S_948CC	0.28	0.03
TK_937	0.05	0.01
WWT_1594	0.05	0.02

Table 4. Minor NSR Project (Increases Only) Modeling Results for Health Effects

Pollutant & CAS# *	Averaging Time	GLCmax (µg/m^3)	10% ESL ** (µg/m^3)
1,3-butadiene 106-99-0	Annual	0.15	0.99
1-butene 106-98-9	Annual	0.02	160
benzene 71-43-2	Annual	0.15	0.45
ethylene 74-85-1	Annual	1	3.4
hexane, mixed isomers 92112-69-1	Annual	0.4	20

* Chemical Abstract Service Number
** Effects Screening Level

VIII. Offsets

The site is located in Harris County, which has been designated as a severe nonattainment area for ozone. The facility is an existing major source of VOC and NO_X, and the project will result in a significant net increase of VOC and NO_X.

The applicant is required to offset 42.42 tpy VOC and 41.62 tpy NOx at a ratio of 1.3 to 1 applicable for the severe ozone nonattainment designation with emission credit reduction credits (ERCs) of 55.1 tpy for VOC and 54.1 tpy for NOx.

When issued, the permit requires that the permit holder offset the project emission increase for facilities authorized by this permit prior to the commencement of operation, through participation in the TCEQ Emission Banking and Trading (EBT) Program in accordance with the rules in 30 TAC Chapter 101, Subchapter H.

Prior to the commencement of operation, the permit holder is required to obtain approval from the TCEQ EBT Program for the credits being used and then submit a permit alteration or amendment request to the TCEQ Air Permits Division (and copy the TCEQ Regional Office) to identify approved credits by TCEQ credit certificate number.

IX. Alternative Site Analysis and Compliance Certification

The applicant has submitted the required demonstration relating to consideration of alternative sites and Clean Air Act compliance status for sites owned or operated by the applicant (or by any entity controlling, controlled by, or under common control with the applicant). The analysis demonstrated that the benefits of the proposed location and source configuration significantly outweigh the environmental and social costs of that location.

X. Conclusion

As described above, the applicant has demonstrated that the project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The Executive Director’s preliminary determination is that the permits should be issued.