TECHNICAL REVIEW DOCUMENT
OPERATING PERMIT 95OPWE055
to be issued to:

Duke Energy Field Services, LP
Roggen Gas Plant
Weld County
Source ID 1230049

Prepared by Geoffrey D. Drissel
January 8, 2001

I. Purpose:

This document establishes the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered within the operating permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA, the Public and other interested parties. The conclusions made in this report are based on information provided in the original application submittal of March 1, 1995 and supplemental technical submittals of September 28, 1995, February 20, 1996, October 3, 1997, December 1, 1999, January 7, 2000 and August 25, 2000. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

On April 16, 1998 the Colorado Air Quality Control Commission directed the Division to implement new procedures regarding the use of short term emission and production/throughput limits on Construction permits. These procedures are being directly implemented in all operating permits that had not started their Public Comment period as of April 16, 1998. All short term emission and production/ throughput limits that appeared in the construction permits associated with this facility that are not required by a specific State or Federal standard or by the above referenced Division procedures have been deleted and all annual emission and production/throughput limits converted to a rolling 12 month total. Note that, if applicable, appropriate modeling to demonstrate compliance with the National Ambient Air Quality Standards was conducted as part of the Construction Permit processing procedures. If required by this permit, portable monitoring results and/or EPA reference test method results will be multiplied by 8760 hours for comparison to annual emission limits unless there is a specific condition in the permit restricting hours of operation.

In order to resolve various compliance issues regarding a number of Duke's facilities, Duke Energy agreed to a Compliance Order on Consent (COC), effective January 8, 1999, that stipulated certain requirements for some of the emission units at the Roggen Plant. Those requirements included the installation of air/fuel ratio controllers on some engines and the cessation of

operation of certain emission units. The COC requirements are summarized as follows:

1. DEFS will ensure that air/fuel ratio controllers and catalytic converters are installed on compressor engines P001, P009, P015, P016, P017, P018 and P019 within 180 days of the effective date of the COC. Emission tests are required to demonstrate compliance with the emission limits. (Note that DEFS elected to remove P009 from service rather than install the required equipment and it is not, therefore, addressed in the draft Operating Permit).
2. DEFS will cease operation of engines P004, P005 and P006, as well as the Randall processing skid, as of the effective date of the COC.
3. The Petrofac and Russell processing skids will be subject to NSPS Subpart KKK 180 days from the effective date of the COC. Note that DEFS reported, in the August 6, 1999 SEP Completion Report, that natural gas processing at Roggen had yet to be restarted from a past temporary cessation of operation. The company committed to tag the affected components on the two skids by mid-August 1999. The Report also explained that the Subpart KKK semi-annual monitoring period would commence when the tagging was completed.

A modification to the COC was agreed to on July 2, 1999. The changes to the COC set forth in the modification were as follows:

1. DEFS will not be required to install emission control devices on emission units P016 and P018. Instead, DEFS will install emission control devices on the next two engines installed and operated at the Roggen Plant.
2. DEFS will conduct stack tests on emission units P015, P017 and P019 within sixty days after each engine commences operation.

An additional modification to the COC was agreed to on January 26, 2000. The change to the COC set forth in that modification authorized DEFS to recommence operation of the Randall natural gas processing unit provided leak detection and repair records are maintained that are consistent with requirements set forth in NSPS Subpart KKK.

DEFS also submitted additional information on December 1, 1999 and January 7, 2000. These submittals deleted engines P011, P016 and P018, modified engines P003, P008, P010 and P012, and created new emission points for the fractionator fugitives and pressurized liquid loadout emissions.

On August 25, 2000 DEFS submitted revised APENs for all of the compressor engines at the facility, with the intent of creating synthetic minor status for the facility with respect to PSD review. Consequently, the NOx and CO potential to

emit were decreased for most of the existing engines. The total permitted NOx emissions for the facility were reduced to 243.8 tons per year from 332.1 tons per year and the total permitted CO emissions for the facility were reduced to 236.9 tons per year from 393.5 tons per year. The emission limits and emission factors contained in the Operating Permit for the engines at the Roggen facility are based on the information provided in the 8/25/00 revised APENs.

PSD Source Status

Upon the effective date of this operating permit, the Roggen facility will be considered a Synthetic Minor Source for purposes of the Prevention of Significant Deterioration (PSD) program. The following summarizes portions of the past permitting history of the facility.

The predecessor of Duke Energy Field Services, LLC (DEFS), Associated Natural Gas Inc. (ANGI) purchased the Roggen plant from Snyder Oil Company (SOCO) on October 1, 1995. The Roggen facility was originally constructed in the late 1950s. In 1981, Crystal Oil owned the facility. Damson Oil purchased it in 1982, and SOCO later purchased it from Damson. In 1981, the Roggen Gas Plant underwent a major modification without undergoing PSD review. In 1982, reductions were made at the facility through the removal of emissions units and installation of control equipment.

On March 17, 1983, EPA issued a Notice of Violation (NOV) to Crystal/Damson for an alleged failure to obtain a PSD permit for a major modification at a major source prior to installing certain compressor engines in 1981 and 1982. Subsequently, Crystal and Damson sought federal court review of EPA's PSD applicability determination. In 1983 a Consent Order was issued to resolve the NOV. The Order took effect on January 21, 1983. The Consent Order required PSD monitoring and served to make the 1982 reductions and controls federally enforceable. It established emissions reductions achieved by Damson in 1982 as federally enforceable.

The Consent Order, by its terms, was to remain in effect until the NOx PTE at the facility dropped below 250 Tons Per Year (TPY) or for 12 years, whichever came first. Since the NOx PTE at Roggen did not drop below 250 TPY during the 12-year period, the Consent Order expired on January 21, 1995. At that time, the facility was in violation of the PSD requirements.

Shortly after ANGI purchased the Roggen facility in October 1995 from SOCO, ANGI realized that, with the expiration of the Consent Order, the emission

reductions made in 1981 and 1982 no longer had federally enforceable requirements to limit the PTE of the modifications to below the PSD significance levels. ANGI brought this issue to the Division's attention in February 1996 and, along with a Title V operating permit application that revised SOCO's earlier Title V filing that failed to capture this issue, applied for construction permits that would effectively limit the PTE of the engines at issue.

As part of the analysis for the February 1996 permit application, ANGI determined that the NOX levels set forth in the EPA Consent Order were inconsistent with both the engine manufacturer's specifications and ANGI's method of operating compressor engines at similar facilities in Weld County. A more realistic emissions estimate from the engines would have exceeded the PSD significance levels in their permit application by 7 TPY. ANGI therefore added additional controls to one of the other engines on site so that the net PTE was below PSD significance levels. By letter dated March 3, 1998, the Division determined that the difference between the actual NOx emissions emitted by the Consent Order engines during the Consent Order time period (based on 1.09 g/hp-hr or less) and the emission limits set in the permit applied for in February 1996 (based on 2.0 g/hp-hr) were less than 40 tons per year, thus not considered significant under the PSD rules.

On July 11, 1997, the Division wrote ANGI a letter stating that "Due to the change in ownership in 1995, and the prompt response by ANGI to address the PSD major modification issue, the Division has determined that no enforcement response is warranted by the failure to obtain the appropriate [PSD] permit prior to the January 21, 1995 significant increase in emissions." In effect, the Division concluded that ANGI's prompt response to the "gap" in federal enforceability caused by the expiration of the 1983 Consent Order did not warrant enforcement.

In January 1999, the Division and DEFS entered a negotiated Compliance Order on Consent (COC) applicable to various DEFS (formerly ANGI) facilities in Weld County, including Roggen. As part of the Settlement in the COC, DEFS agreed to remove from service three grandfathered, uncontrolled compressor engines that were first installed at Roggen in the late 1950's, to install additional controls on several other compressor engines at the site, and to permanently surrender the resulting emissions reduction credits.

In August 2000 DEFS approached the Division with a request to permit the Roggen facility as a synthetic minor source for PSD. DEFS is requesting emission factors of 2.1 g/hp-hr for NOx and CO and 1 g/hp-hr for VOC for all engines located at Roggen. After researching EPA policy memos on this topic,

the Division has decided to grant DEFS's request.

At issue is what is commonly referred to as EPA's "once in-always in" policy as it refers to the PSD program. In general terms, the policy is commonly thought to mean that once you are in the PSD program you can never get out of the requirements even though the source emissions may fall below PSD levels.

The primary EPA documents used in the Division's determination that a major source can be converted to a synthetic minor source are: EPA Region IV "Policy Determinations Regarding PSD Questions", question #8, dated 6/5/81; EPA December 1987 memo from Bruce Miller to Gary McCutcheon; EPA February 4,1988 memo from John Rasnic to Bruce Miller; and the EPA November 17, 1998 memo from Eric Schaeffer regarding Injunctive Relief for violations of major NSR requirements.

These documents confirm that a facility with actual emissions in excess of major source thresholds may secure synthetic minor status by taking federally enforceable limits on its potential to emit provided that the source never actually triggered PSD review and/or proper penalties were assessed to remove the economic benefit of any PSD-related violation.

In conclusion, the 1983 Consent Order represented appropriate enforcement response against previous owners and operators of the Roggen plant. In addition, under the Division's January 1999 COC, DEFS agreed to remove the oldest, highest emitting grandfathered engines at Roggen from service and to essentially install BACT on all of the existing engines. While a PSD violation technically occurred in 1995 after the EPA Consent Order expired and before the new owner applied for new permits, ANGI promptly reported the issue to the Division and sought the appropriate permits to remedy the situation, thus limiting the duration of the federal enforceability "gap" created by the expiration of the Order. The Division's July 11, 1997 and March 3, 1998 letters closed out the enforcement issues related to that matter. Further, that excursion was a very unusual, and probably unique, circumstance. Additionally, all engines currently at the facility are well-controlled via the Division's COC even though no formal PSD review has ever occurred. For these reasons, the synthetic minor source status of the plant is appropriate.

II. Source Description:

This source is classified as a natural gas liquids production facility defined under Standard Industrial Classification 1321. The plant processes natural gas using

refrigeration and cryogenic processes. The gas is compressed at various points in the process using twelve Internal Combustion Engines to power twelve compressor units. Additional equipment includes two process heaters, three gas processing skids (Randall, Russell and Petrofac), a glycol dehydration unit and several storage tanks.

The facility is located in a rural area south of Roggen in Weld County, Colorado, in an area designated as attainment for all criteria pollutants. Facility-wide potential and actual emissions are as follows:

Pollutant	Revised Potential to Emit (tpy)	Actual Emissions (tpy)
NOx	243.8	243.8
VOC	170.6	170.6
CO	236.9	236.9

Potential emissions are taken from the revised APENs submitted by DEFS on August 25, 2000. At the request of DEFS, actual emissions are represented to be the same as potential emissions. The Division assumes that emissions from the facility have remained the same or decreased from the levels listed above.

The applicant certified that the facility was in compliance with all applicable requirements at the time of the October 3, 1997 submittal of additional information. The applicant also indicated, in the February 20, 1996 application resubmittal, that the facility is not subject to 112(r), the Accidental Release Prevention Program of the Federal Clean Air Act.

III. Emission Sources:

In August 2000 DEFS submitted revised APENs for the engines at the Roggen facility that established emission limits that make Roggen a synthetic minor source for PSD purposes. Recent stack testing to verify emissions has been conducted on all but four of the engines. Consequently, a stack testing requirement for those four engines (p003, P008, P010 and P012) will be incorporated into the Operating Permit.

The following sources are specifically regulated under terms and conditions of the operating permit for this Site:

Unit P001- Waukesha Model 7042GSI Natural Gas Fired Internal Combustion/ Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 1,100 HP, Serial No. 360925

Discussion:

1. Applicable Requirements- Prior to the Operating Permit application submittal, this source was rated at a lower horsepower and was considered exempt from permitting. As part of the original Operating Permit application, a request was made that this source be permitted. On August 25, 2000, DEFS submitted a revised APEN for this unit which modified the annual emission limits for NOx, CO and VOC. The g/hp-hr factors listed on the revised APEN were used to generate the following permit terms:

Parameter	Short Term Limit	Long Term Limit
NOx	5.09 lbs/hr	22.3 tons/yr
CO	5.09 lbs/hr	22.3 tons/yr
VOC	2.42 lbs/hr	10.6 tons/yr
Fuel Use	8.84 scf/hr	77.45 MMscf/yr

As mentioned above, the short term limits will not be incorporated into the Operating Permit. The annual NOx, CO, VOC and fuel use limitations and the 20% opacity limit will be incorporated into the Operating Permit.

2. Emission Factors- Emissions from this reciprocating engine are produced during the combustion process, and are dependent upon the air to fuel ratio adjustment and specific properties of the natural gas being burned. The pollutants of concern are nitrogen oxides (NOx), carbon monoxide (CO) and volatile organic compounds (VOCs). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted when combustion is incomplete. Emissions of NOx, CO and VOC from this engine will be calculated using emission factors and the hourly design heat input provided in the 8/25/00 revised APENs. Detailed calculations demonstrating this derivation are provided in the attached Summary of Emission Factor Derivations. The derived emission factors are as follows:

Pollutant	Emission Factor	Source
NOx	0.601 lb/MMBtu	Calculation
CO	0.601 lb/MMBtu	Calculation
VOC	0.286 lb/MMBtu	Calculation

3. Monitoring Plan- Conditions 1.1 through 1.4, 14.1, 15.1, 16.1 and 16.2 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with applicable requirements for this engine. The monitoring requirements for this engine is described in Section IV of this document - Monitoring Plan for Points P001-P019.

4. Compliance Status- The applicant certified in the operating permit application that this engine was in compliance with all applicable requirements at the time of submittal. Lacking any evidence to the contrary, this source is considered to be in compliance with all applicable requirements.

Unit P002- Waukesha Model 7042G Natural Gas Fired Internal Combustion Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 806 HP, Serial No. 253828

Unit P007- Waukesha Model 7042G Natural Gas Fired Internal Combustion Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 806 HP, Serial No. 335512

Unit P013- Waukesha Model 7042G Natural Gas Fired Internal Combustion Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 806 HP, Serial No. 361724

Unit P014- Waukesha Model 7042G Natural Gas Fired Internal Combustion Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 806 HP, Serial No. 329742

Discussion:

1. Applicable Requirements- Prior to the Operating Permit application submittal, three of these engines were governed by a previous Consent Order and one was considered exempt from permitting. As part of the original Operating Permit application, a request was made that these sources be permitted. On August 25, 2000, DEFS submitted a revised APEN for these units which modified the annual emission limits for NOx, CO and VOC. The g/hp-hr factors listed on the revised APENs were used to generate the following permit terms:

	Short	Long

Parameter	Term Limit	Term Limit
NOx	3.73 lbs/hr	16.34 tons/yr
CO	3.73 lbs/hr	16.34 tons/yr
VOC	1.78 lbs/hr	7.8 tons/yr
Fuel Use	7,516 scf/hr	65.84 MMscf/yr

As mentioned above, the short term limits will not be incorporated into the Operating Permit. The annual NOx, CO, VOC and fuel use limitations and the 20% opacity limit will be incorporated into the Operating Permit.

2. Emission Factors- Emissions from these reciprocating engines are produced during the combustion process, and are dependent upon the air to fuel ratio adjustment and specific properties of the natural gas being burned. The pollutants of concern are nitrogen oxides (NOx), carbon monoxide (CO) and volatile organic compounds (VOCs). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted when combustion is incomplete. Emissions of NOx, CO and VOC from these engines will be calculated using emission factors and the hourly design heat input provided in the 8/25/00 revised APENs. Detailed calculations demonstrating this derivation are provided in the attached Summary of Emission Factor Derivations. The derived emission factors are as follows:

Pollutant	Emission Factor	Source
NOx	0.518 lb/MMBtu	Calculation
CO	0.518 lb/MMBtu	Calculation
VOC	0.247 lb/MMBtu	Calculation

3. Monitoring Plan- Conditions 2.1 through 2.4, 14.1, 15.1, 16.1 and 16.2 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with applicable requirements for these engines. The monitoring requirements for these engines is described in Section IV of this document - Monitoring Plan for Points P001-P019.

4. Compliance Status- The applicant certified in the operating permit application that these engines were in compliance with all applicable requirements at the time of submittal. Lacking any evidence to the contrary, this source is considered to be in compliance with all applicable requirements.

Unit P003- Waukesha Model 7042GSI Natural Gas Fired Internal Combustion

Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 1,350 HP, Serial No. Not Available

Unit P008- Waukesha Model 7042GSI Natural Gas Fired Internal Combustion Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 1,350 HP, Serial No. Not Available

Unit P012- Waukesha Model 7042GSI Natural Gas Fired Internal Combustion Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 1,350 HP, Serial No. Not Available

Discussion:

1. Applicable Requirements- Prior to the Operating Permit application submittal, Colorado Construction Permits 85WE262-1 and 92WE637-3 defined applicable requirements for two of these engines. The third was considered exempt. On August 25, 2000, DEFS submitted a revised APEN for these units which modified the annual emission limits for NOx, CO and VOC. The g/hp-hr factors listed on the revised APENs were used to generate the following permit terms:

Parameter	Short Term Limit	Long Term Limit
NOx	6.25 lbs/hr	27.38 tons/yr
CO	6.25 lbs/hr	27.38 tons/yr
VOC	2.98 lbs/hr	13.04 tons/yr
Fuel Use	11,575 scf/hr	101.4 MMscf/yr

As mentioned above, the short term limits will not be incorporated into the Operating Permit. The annual NOx, CO, VOC and fuel use limitations and the 20% opacity limit will be incorporated into the Operating Permit.

2. Emission Factors- Emissions from these reciprocating engines are produced during the combustion process, and are dependent upon the air to fuel ratio adjustment and specific properties of the natural gas being burned. The pollutants of concern are nitrogen oxides (NOx), carbon monoxide (CO) and volatile organic compounds (VOCs). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted when combustion is incomplete. Emissions of NOx, CO and VOC from these engines will be calculated using emission factors and the hourly design heat input provided in the 8/25/00 revised APENs. Detailed calculations demonstrating this derivation are provided in the attached Summary of

Emission Factor Derivations. The derived emission factors are as follows:

Pollutant	Emission Factor	Source
NOx	0.564 lb/MMBtu	Calculation
CO	0.564 lb/MMBtu	Calculation
VOC	0.268 lb/MMBtu	Calculation

3. Monitoring Plan- Conditions 3.1 through 3.4, 14.1, 15.1, 16.1 and 16.2 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with applicable requirements for these engines. The monitoring requirements for these engines are described in Section IV of this document - Monitoring Plan for Points P001-P019.

4. Compliance Status- The applicant certified in the operating permit application that these engines were in compliance with all applicable requirements at the time of submittal. Lacking any evidence to the contrary, this source is considered to be in compliance with all applicable requirements.

Unit P010- Waukesha Model 7042GSI Natural Gas Fired Internal Combustion Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 1,150 HP, Serial No. Not Available

Discussion:

1. Applicable Requirements- Prior to the Operating Permit application submittal, Colorado Construction Permit 92WE637-1 was written which defined applicable requirements for this engine. On August 25, 2000, DEFS submitted a revised APEN for this unit which modified the annual emission limits for NOx, CO and VOC. The g/hp-hr factors listed on the revised APEN were used to generate the following permit terms:

Parameter	Short Term Limit	Long Term Limit
NOx	5.32 lbs/hr	23.32 tons/yr
CO	5.32 lbs/hr	23.32 tons/yr
VOC	2.53 lbs/hr	11.1 tons/yr
Fuel Use	9,395 scf/hr	82.3 MMscf/yr

As mentioned above, the short term limits will not be incorporated into the Operating Permit. The annual NOx, CO, VOC and fuel use limitations and

the 20% opacity limit will be incorporated into the Operating Permit.

2. Emission Factors- Emissions from this reciprocating engine are produced during the combustion process, and are dependent upon the air to fuel ratio adjustment and specific properties of the natural gas being burned. The pollutants of concern are nitrogen oxides (NOx), carbon monoxide (CO) and volatile organic compounds (VOCs). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted when combustion is incomplete. Emissions of NOx, CO and VOC from this engine will be calculated using emission factors and the hourly design heat input provided in the 8/25/00 revised APENs. Detailed calculations demonstrating this derivation are provided in the attached Summary of Emission Factor Derivations. The derived emission factors are as follows:

Pollutant	Emission Factor	Source
NOx	0.592 lb/MMBtu	Calculation
CO	0.592 lb/MMBtu	Calculation
VOC	0.282 lb/MMBtu	Calculation

3. Monitoring Plan- Conditions 4.1 through 4.4, 14.1, 15.1, 16.1 and 16.2 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with applicable requirements for this engine. The monitoring requirements for this engine are described in Section IV of this document - Monitoring Plan for Points P001-P019.

4. Compliance Status- The applicant certified in the operating permit application that this engine was in compliance with all applicable requirements at the time of submittal. Lacking any evidence to the contrary, this source is considered to be in compliance with all applicable requirements.

Unit P015- Superior Model 8G825 Natural Gas Fired Internal Combustion Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 720 HP, Serial No. 20868

Unit P017- Superior Model 8G825 Natural Gas Fired Internal Combustion Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and Catalyst, Rated at 720 HP, Serial No. 20709

Unit P019- Superior Model 8G825 Natural Gas Fired Internal Combustion Engine, 4 Cycle, Rich Burn, Equipped with A/F Ratio Controller and

Catalyst, Rated at 720 HP, Serial No. 264009

Discussion:

1. Applicable Requirements- Prior to the Operating Permit application submittal, these sources were considered exempt from permitting. On August 25, 2000, DEFS submitted a revised APEN for this unit which modified the annual emission limits for NOx, CO and VOC. The g/hp-hr factors listed on the revised APEN were used to generate the following permit terms:

Parameter	Short Term Limit	Long Term Limit
NOx	3.33 lbs/hr	14.6 tons/yr
CO	3.33 lbs/hr	14.6 tons/yr
VOC	1.6 lbs/hr	7.0 tons/yr
Fuel Use	6,471 scf/hr	56.69 MMscf/yr

As mentioned above, the short term limits will not be incorporated into the Operating Permit. The annual NOx, CO, VOC and fuel use limitations and the 20% opacity limit will be incorporated into the Operating Permit.

2. Emission Factors- Emissions from these reciprocating engines are produced during the combustion process, and are dependent upon the air to fuel ratio adjustment and specific properties of the natural gas being burned. The pollutants of concern are nitrogen oxides (NOx), carbon monoxide (CO) and volatile organic compounds (VOCs). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted when combustion is incomplete. Emissions of NOx, CO and VOC from these engines will be calculated using emission factors and the hourly design heat input provided in the 8/25/00 revised APENs. Detailed calculations demonstrating this derivation are provided in the attached Summary of Emission Factor Derivations. The derived emission factors are as follows:

Pollutant	Emission Factor	Source
NOx	0.538 lb/MMBtu	Calculation
CO	0.538 lb/MMBtu	Calculation
VOC	0.258 lb/MMBtu	Calculation

3. Monitoring Plan- Conditions 5.1 through 5.4, 14.1, 15.1, 16.1 and 16.2 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with applicable requirements for

these engines. The monitoring requirements for these engines is described in Section IV of this document - Monitoring Plan for Points P001-P019.

4. Compliance Status- The applicant certified in the operating permit application that these engines were in compliance with all applicable requirements at the time of submittal. Lacking any evidence to the contrary, this source is considered to be in compliance with all applicable requirements.

Unit H022- Born Natural Gas Fired Depropanizer Heater Rated at 7.0 MMBTU, Serial No. 920

Discussion:

1. Applicable Requirements- Prior to the Operating Permit application submittal, Colorado Construction Permit 82WE157-3 defined applicable requirements for this heater. A subsequent APEN revision established annual NOx and fuel use limitations as follows:

Parameter	Short Term Limit	Long Term Limit
NOx	0.8 lbs/hr	3.2 tons/yr
Fuel Use	7,306 scf/hr	64.0 MMscf/yr

As mentioned above, the short term limits will not be incorporated into the Operating Permit. The Regulation No. 1 particulate limit for fuel burning equipment will be included as an applicable requirement because it defines a short term limit. The annual NOx and fuel use limitations and the 20% opacity limit will be incorporated into the Operating Permit.

2. Emission Factors- Emissions from this heater are produced during the combustion process, and are dependent upon certain operating parameters and specific properties of the natural gas being burned. The pollutants of concern are nitrogen oxides (NOx) and carbon monoxide (CO) and volatile organic compounds (VOCs). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted when combustion is incomplete. NOx emissions will be calculated using emission factor derived from the annual emission limit and annual fuel use limit listed in the Construction Permit. Detailed calculations demonstrating this derivation are provided in the attached Summary of Emission Factor

Derivations. The derived emission factor is as follows:

Pollutant	Emission Factor	Source
NOx	0.104 lb/MMBtu	Calculation

3. Monitoring Plan- Conditions 6.1 through 6.5 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with applicable requirements for this heater. Specific monitoring guidance for heaters in attainment areas has been developed by the Division as shown on the attached grid titled "Compliance/Scenario Summary - Gas Fired Boilers." This grid defines emission calculation and measurement of fuel use as the minimum requirements for this heater.

Because Construction Permit 97WE0340 contains an annual emission limit for NOx, the applicant will be required to calculate emissions monthly using actual monthly fuel use and the fuel-based emission factor. Rolling twelve month emission and fuel use totals will be maintained for comparison with the annual emission and fuel use limits.

Emission calculations for fee purposes will be based on actual annual fuel use and the fuel-based emission factor. The applicant will be required to conduct the emission calculation annually and submit a revised APEN to the Division if emissions increase as described in Regulation No. 3, Part A, Section II.C.2.

Compliance with the opacity standard of 20% will be monitored by a certification that the heater has used natural gas exclusively during the reporting period. The Division has determined, based on AP-42 emission factors and engineering judgement, that particulate emissions from this heater will be insignificant if natural gas is used as the fuel.

4. Compliance Status- The applicant certified in the operating permit application that this heater was in compliance with all applicable requirements at the time of submittal. Using AP-42 emission factors, maximum fuel input and annual operating hours to calculate this source's potential to emit, the construction permit emission limits cannot be exceeded. The use of natural gas satisfies the opacity and Regulation No. 1 particulate limits. Thus, this source is considered to be in compliance with all applicable requirements.

Unit H024- Mann-Loveco Natural Gas Fired Hot Oil Heater Rated at 8.0 MMBTU, Serial No. C76071

Discussion:

1. Applicable Requirements- Prior to the Operating Permit application submittal, Colorado Construction Permit 82WE157-2 defined applicable requirements for this heater. A subsequent APEN revision established annual NOx and fuel use limitations as follows:

Parameter	Short Term Limit	Long Term Limit
NOx	0.9 lbs/hr	3.7 tons/yr
Fuel Use	8,357 scf/hr	73.2 MMscf/yr

As mentioned above, the short term limits will not be incorporated into the Operating Permit. The Regulation No. 1 particulate limit for fuel burning equipment will be included as an applicable requirement because it defines a short term limit. The annual NOx and fuel use limitations and the 20% opacity limit will be incorporated into the Operating Permit.

2. Emission Factors- Emissions from this heater are produced during the combustion process, and are dependent upon certain operating parameters and specific properties of the natural gas being burned. The pollutants of concern are nitrogen oxides (NOx) and carbon monoxide (CO) and volatile organic compounds (VOCs). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted when combustion is incomplete. NOx emissions will be calculated using emission factor derived from the annual emission limit and annual fuel use limit listed in the Construction Permit. Detailed calculations demonstrating this derivation are provided in the attached Summary of Emission Factor Derivations. The derived emission factor is as follows:

Pollutant	Emission Factor	Source
NOx	0.106 lb/MMBtu	Calculation

3. Monitoring Plan- Conditions 7.1 through 7.5 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with applicable requirements for this heater. Specific monitoring guidance for heaters in attainment areas has been developed by the Division as shown on the attached grid titled "Compliance/Scenario Summary - Gas Fired Boilers." This grid defines

emission calculation and measurement of fuel use as the minimum requirements for this heater.

Because Construction Permit 97WE0340 contains an annual emission limit for NOx, the applicant will be required to calculate emissions monthly using actual monthly fuel use and the fuel-based emission factor. Rolling twelve month emission and fuel use totals will be maintained for comparison with the annual emission and fuel use limits.

Emission calculation for fee purposes will be based on actual annual fuel use and the fuel-based emission factor. The applicant will be required to conduct the emission calculation annually and submit a revised APEN to the Division if emissions increase as described in Regulation No. 3, Part A, Section II.C.2.

Compliance with the opacity standard of 20% will be monitored by a certification that the heater has used natural gas exclusively during the reporting period. The Division has determined, based on AP-42 emission factors and engineering judgement, that particulate emissions from this heater will be insignificant if natural gas is used as the fuel.

4. Compliance Status- The applicant certified in the operating permit application that this heater was in compliance with all applicable requirements at the time of submittal. Using AP-42 emission factors, maximum fuel input and annual operating hours to calculate this source's potential to emit, the construction permit emission limits cannot be exceeded. The use of natural gas satisfies the opacity and Regulation No. 1 particulate limits. Thus, this source is considered to be in compliance with all applicable requirements.

<u>Unit F025</u>- Russell Gas Plant Fugitive Emissions

Discussion:

1. Applicable Requirements - The DEFS submittal of January 7, 2000 established the annual limits for this skid to be 6.75 tons VOC per year. That limit has been incorporated into the draft Operating Permit as an applicable requirement.

As stipulated in the 1/8/99 COC, this plant is considered to be subject to 40CFR60 Subpart KKK. This subpart contains requirements for

inspection and monitoring of fugitive leaks at this unit.

2. Emission Factors - Emissions from this source consist of VOC leaks from equipment and associated piping and components at the facility. Emissions from leaking equipment and piping are estimated using facility component counts and EPA emission factors as described in the 1995 EPA document "Protocol for Equipment Leak Emission Estimates".

3. Monitoring Plan - Conditions 8.1 through 8.3 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with the applicable requirements. Specifically, DEFS must maintain an annual accounting of the number of all equipment components, by tracking all component additions and deletions, that could contribute to fugitive VOC leaks. The resulting leak calculation will be compared to the annual VOC limit to determine compliance. No specific component limit has been specified in the Operating Permit to allow flexibility under the VOC emission limitation.

4. Compliance Status - The applicant certified in the operating permit application that this source was in compliance with all applicable requirements at the time of submittal. Lacking any evidence to the contrary, this source is considered to be in compliance with all applicable requirements.

<u>Unit F026</u>- Randall Gas Plant Fugitive Emissions

Discussion:

1. Applicable Requirements - The 1/8/99 COC required that operation of this skid be discontinued. The 1/4/00 modification to the COC authorized DEFS to recommence operation of this skid if DEFS agrees to conduct a leak detection and repair program consistent with the monitoring program detailed in 40 CFR, Part 60, Subpart KKK. The DEFS submittal of January 7, 2000 specified the annual limits for this skid as 6.75 tons VOC per year. This limit has been incorporated into the draft Operating Permit.

2. Emission Factors - Emissions from this source consist of VOC leaks from equipment and associated piping and components at the facility. Emissions from leaking equipment and piping are estimated using facility component counts and EPA emission factors as described in the 1995

EPA document "Protocol for Equipment Leak Emission Estimates".

3. Monitoring Plan - Conditions 9.1 and 9.2 of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with the applicable requirements. Specifically, DEFS must maintain an annual accounting of the number of all equipment components, by tracking all component additions and deletions, that could contribute to fugitive VOC leaks. The resulting leak calculation will be compared to the annual VOC limit to determine compliance. No specific component limit has been specified in the Operating Permit to allow flexibility under the VOC emission limitation.

4. Compliance Status - The applicant certified in the operating permit application that this source was in compliance with all applicable requirements at the time of submittal. Lacking any evidence to the contrary, this source is considered to be in compliance with all applicable requirements.

<u>Unit F027</u>- Petrofac Gas Plant Fugitive Emissions

Discussion:

1. Applicable Requirements - Prior to the Operating Permit application submittal, Colorado Construction Permit 92WE637-4 defined applicable requirements for this heater. A subsequent APEN revision established the annual VOC emission limit of 4.1 tons per year, which has been incorporated into the draft Operating Permit as an applicable requirement.

This plant is considered to be an onshore natural gas processing facility as defined in 40CFR60 Subpart KKK. This subpart contains requirements for inspection and monitoring of fugitive leaks at these facilities. The effective date for this subpart is January 20, 1984. Since the NGL plant began operation, or was modified, after that date, Subpart KKK applies to this unit.

2. Emission Factors - Emissions from this source consist of VOC leaks from equipment and associated piping and components at the facility. Emissions from leaking equipment and piping are estimated using facility component counts and EPA emission factors as described in the 1995 EPA document "Protocol for Equipment Leak Emission Estimates".

3. Monitoring Plan - Conditions 10.1 through 10.3 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with the applicable requirements. Specifically, DEFS must maintain an annual accounting of the number of all equipment components, by tracking all component additions and deletions, that could contribute to fugitive VOC leaks. The resulting leak calculation will be compared to the annual VOC limit to determine compliance. No specific component limit has been specified in the Operating Permit to allow flexibility under the VOC emission limitation.

4. Compliance Status - The applicant certified in the operating permit application that this source was in compliance with all applicable requirements at the time of submittal. Lacking any evidence to the contrary, this source is considered to be in compliance with all applicable requirements.

<u>Unit F029</u>- Condensate Loadout VOC Emissions

Discussion:

1. Applicable Requirements - The DEFS submittal of January 7, 2000 modified the annual limits for this emission point. In that submittal, DEFS split the loadout emissions into a condensate loadout source (F029) and a pressurized liquids loadout source (F031). The annual VOC emission limit of 25.0 tons per year estimated by DEFS has been incorporated into the draft Operating Permit as an applicable requirement, along with the loadout quantity limit.

2. Emission Factors - VOC emissions from this source result from vapor losses that occur during the loading of condensate into cargo tanks. The magnitude of the losses are dependent on the method of loading the condensate and the physical and chemical characteristics of the condensate. Emissions of VOC's will be calculated using an emission factor derived from the following AP-42 equation:

$$L_L = 12.46 \times S \times P \times M \div T$$

where:

L_L = loading loss, pounds per 1000 gallons of liquid loaded
S = a saturation factor = 0.6 for submerged loading
P = vapor pressure of liquid loaded = 3.41 psia

M = molecular weight of vapors = 88.5 lb/lb-mol
T = temperature of liquid loaded = 519.3? R

That factor is 4.34 pounds of VOC emissions per 1,000 gallons of condensate loaded.

3. Monitoring Plan - Conditions 11.1 and 11.2 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with the applicable requirements. Because VOC emissions are a direct result of the amount of condensate loaded, compliance with the annual emission limit will be assumed as long as the annual loadout limit is not exceeded.

The amount of condensate loaded will be calculated monthly and a rolling 12 month total will be calculated to determine compliance with the annual loadout limit.

Emission calculations for fee purposes will be based on the loadout emission factor listed above and actual annual condensate loadout. The applicant will be required to conduct the emission calculation annually and submit a revised APEN to the Division if emissions increase by the levels described in Colorado Regulation No. 3, Part A, Section II.C.2, compared to the latest APEN on file with the Division.

4. Compliance Status - This source of emissions was not included in the original Operating Permit application. The Initial Approval Construction Permit for this source was issued in January 1998. The certification provided in the first semi-annual monitoring report will be considered to demonstrate compliance with the Initial Approval permit terms. Consequently, it is assumed that this source is in compliance with all applicable requirements.

<u>Unit F030</u>- Fractionator Plant Fugitive Emissions

Discussion:

1. Applicable Requirements - Emissions from the fractionator plant were originally incorporated into the emissions from the Russell, Randall and Petrofac processing skids. In the 12/1/99 submittal, DEFS elected to establish these emissions as a separate emission source. The annual VOC emission limit of 10.0 tons per year estimated by DEFS in that

submittal has been incorporated into the draft Operating Permit as an applicable requirement.

This plant is considered to be an onshore natural gas processing facility as defined in 40CFR60 Subpart KKK. This subpart contains requirements for inspection and monitoring of fugitive leaks at these facilities. The effective date for this subpart is January 20, 1984. Since the fractionator plant began operation, or was modified, after that date, Subpart KKK applies to this unit.

2. Emission Factors - Emissions from this source consist of VOC leaks from equipment and associated piping and components at the facility. Emissions from leaking equipment and piping are estimated using facility component counts and EPA emission factors as described in the 1995 EPA document "Protocol for Equipment Leak Emission Estimates".

3. Monitoring Plan - Conditions 12.1 through 12.3 of Section II of the Operating Permit list the monitoring and recordkeeping provisions necessary to verify compliance with the applicable requirements. Specifically, DEFS must maintain an annual accounting of the number of all equipment components, by tracking all component additions and deletions, that could contribute to fugitive VOC leaks. The resulting leak calculation will be compared to the annual VOC limit to determine compliance. No specific component limit has been specified in the Operating Permit to allow flexibility under the VOC emission limitation.

4. Compliance Status - This emission source was originally included in other emission points within the Roggen facility, which the applicant certified as being in compliance with all applicable requirements. Lacking any evidence to the contrary, this source is considered to be in compliance with all applicable requirements.

<u>Unit F031</u>- Pressurized Liquids Loadout VOC Emissions

Discussion:

1. Applicable Requirements - The DEFS submittal of December 1, 1999 split the loadout emissions into a condensate loadout source (F029) and a pressurized liquids loadout source (F031). The annual VOC emission limit of 5.0 tons per year estimated by DEFS for the pressurized liquids source has been incorporated into the draft Operating Permit as an

applicable requirement.

2. Emission Factors - VOC emissions from this source result from vapor losses that occur during the loading of pressurized liquid product into cargo tanks. The losses occur from the liquid and vapor hoses that connect the cargo trucks to the storage tanks. The magnitude of the losses are dependent on the diameter and length of the hoses, the pressure of the storage tanks, the number of loadout events per year and the physical and chemical characteristics of the product being loaded. Emissions of VOC's will be calculated using emission factors derived from calculations provided by DEFS in the 12/1/99 submittal. Those emission factors are as follows:

Product	Emission Factor
Propane	0.886 lb VOC/truckload
Butane	0.905 lb VOC/truckload
Gasoline	1.053 lb VOC/truckload

3. Monitoring Plan - Condition 13.1 of Section II of the Operating Permit lists the monitoring and recordkeeping provisions necessary to verify compliance with the applicable requirements. The applicant will be required to calculate emissions monthly using actual number of trucks of each product that were loaded with each product and the emission factors listed above. Rolling twelve month emission and truckload totals will be maintained for comparison with the annual emission limit.

Emission calculations for fee purposes will be based on the annual number of truckloads of each product and the loadout emission factors listed above. The applicant will be required to conduct the emission calculation annually and submit a revised APEN to the Division if emissions increase by the levels described in Colorado Regulation No. 3, Part A, Section II.C.2, compared to the latest APEN on file with the Division.

4. Compliance Status - This emission source was originally included as part of another emission point within the Roggen facility, which the applicant certified as being in compliance with all applicable requirements. Lacking any evidence to the contrary, this source is considered to be in compliance with all applicable requirements.

IV. Monitoring Plan for Points P001-P019

Specific monitoring guidance for internal combustion engines in attainment areas has been developed by the Division. Because the NOx and CO emission factors that were submitted on the 8/25/00 revised APENs are lower than AP-42, the source will be required to perform quarterly portable monitoring to verify both the emission rate and the emission factors for NOx and CO. Simultaneous verification of the CO emission rate and emission factor will be required because of the correlation between NOx and CO emissions. In addition, the applicant will evaluate the performance of the air/fuel ratio controller and record the air/fuel ratio controller set point and the current indicator reading at least once per week. The catalytic converter inlet temperature, outlet temperature, inlet pressure and outlet pressure will be measured at least once per calendar month.

Emissions of NOx, CO and VOC will be calculated monthly using actual fuel use and the fuel based emission factors. A rolling 12 month emission total will be calculated to determine compliance with the annual emission limits.

The Division has determined that emission calculations for fee purposes will be based on the fuel based emission factors listed above and actual annual fuel use. The applicant will be required to conduct the emission calculation annually and submit a revised APEN to the Division if emissions increase by the levels described in Colorado Regulation No. 3, Part A, Section II.C.2, compared to the latest APEN on file with the Division.

Compliance with the opacity standard of 20% will be monitored by a certification that each engine has used natural gas exclusively during the reporting period. The Division has determined, based on AP-42 emission factors and engineering judgement, that particulate emissions from each engine will be insignificant if the listed condition is met.

V. Insignificant Activities

Several insignificant activities were listed by the applicant as an addendum to form 102B. These activities include lube oil, methanol, NGL and solvent storage tanks, as well as various heater treaters and a glycol reboiler, all of which were deemed insignificant based on size or emission level.

VI. Alternative Operating Scenarios

An alternative operating scenario has been included in the Operating Permit that

provides for temporary replacement of compressor engines necessitated by engine breakdown, periodic maintenance or major overhaul. This scenario allows temporary replacement with the same or different engines as currently exists for each emission point and permanent replacement with the same engine as currently exists.

VII. Permit Shield

This facility does not appear to be a major source of Hazardous Air Pollutants at this time. Consequently, the permit shield has been granted for the MACT Standard for Oil and Natural Gas Production Facilities, Part 63, Subpart HH.

VIII. Accidental Release Program - 112(r)

A provision under Part 70 of the Clean Air Act (amended) is the Accidental Release provisions of section 112(r). Under this program, EPA established a list of substances which pose the greatest risk of death or serious injury to humans or extreme harm to the environment. Additionally, a list of flammable substances and high explosives were set forth. Each substance was given a threshold or de minimis level by considering their individual toxicity, reactivity, volatility, flammability, explosiveness, and dispersiveness. Facilities using any of these substances in greater-than-threshold quantities are required to prepare and implement a Risk Management/Prevention Plan for those substances.

The applicant, in the February 20, 1996 submittal, indicated that this facility is not subject to section 112(r).