SRI/USEPA-GHG-QAP-19
April 2002

Test and Quality Assurance Plan

COMM Engineering, USA
EVRU^{TM}

Prepared by:

Greenhouse Gas Technology Center
Southern Research Institute

Under a Cooperative Agreement With
U.S. Environmental Protection Agency

EPA REVIEW NOTICE

SRI/USEPA-GHG-QAP-19
April 2002

Greenhouse Gas Technology Center

A U.S. EPA Sponsored Environmental Technology Verification (ETV) Organization

Test and Quality Assurance Plan
COMM Engineering, USA
Environmental Vapor Recovery Unit (EVRU™)

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U.S. EPA Office of Research and Development QA Team ☒

☒ indicates comments are integrated into Plan

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COMM Engineering, USA
Environmental Vapor Recovery Unit (EVRU™)

This Test and Quality Assurance Plan has been reviewed and approved by the Greenhouse Gas Technology Center Project Manager and Center Director, the U.S. EPA APPCD Project Officer, and the U.S. EPA APPCD Quality Assurance Manager.

Original signed by:

Stephen Piccot Date
Center Director
Greenhouse Gas Technology Center
Southern Research Institute

Original signed by:

David Kirchgessner Date
APPCD Project Officer
U.S. EPA

Original signed by:

Sushma Masemore Date
Project Manager
Greenhouse Gas Technology Center
Southern Research Institute

Original signed by:

Nancy Adams Date
APPCD Quality Assurance Manager
U.S. EPA

Test Plan Final: April 2002

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1.0 INTRODUCTION

1.1 BACKGROUND

The U.S. Environmental Protection Agency's Office of Research and Development (EPA-ORD) operates the Environmental Technology Verification (ETV) program to facilitate the deployment of innovative technologies through performance verification and information dissemination. The goal of ETV is to further environmental protection by substantially accelerating the acceptance and use of improved and innovative environmental technologies. The ETV program is funded by Congress in response to the belief that there are many viable environmental technologies that are not being used for the lack of credible third-party performance data. With performance data developed under this program, technology buyers, financiers, and permitters in the United States and abroad will be better equipped to make informed decisions regarding environmental technology purchase and use.

The Greenhouse Gas Technology Center (GHG Center) is one of six verification organizations operating under the ETV program. The GHG Center is managed by EPA's partner verification organization, Southern Research Institute (SRI), which conducts verification testing of promising GHG mitigation and monitoring technologies. The GHG Center's verification process consists of developing verification protocols, conducting field tests, collecting and interpreting field and other data, obtaining independent peer-review input, and reporting findings. Performance evaluations are conducted according to externally reviewed verification Test and Quality Assurance Plans (Test Plan) and established protocols for quality assurance.

The GHG Center is guided by volunteer groups of stakeholders. These stakeholders offer advice on specific technologies most appropriate for testing, help disseminate results, and review Test Plans and Verification Reports and Statements (Verification Report). The GHG Center's Executive Stakeholder Group consists of national and international experts in the areas of climate science and environmental policy, technology, and regulation. It also includes industry trade organizations, environmental technology finance groups, governmental organizations, and other interested groups. The GHG Center's activities are also guided by industry specific stakeholders who provide guidance on the verification testing strategy related to their area of expertise and peer-review key documents prepared by the GHG Center.

The GHG Center's Oil and Natural Gas Stakeholder Group have voiced support for the GHG Center's mission, and have identified a need for independent third-party verification of technologies that cost effectively reduce methane (CH_4) and carbon dioxide (CO_2) emissions. Verifications have been conducted for technologies applicable to the oil and natural gas production, transmission, and distribution sectors. This Verification Report documents the testing plans for a new technology that recovers and utilizes vapors from crude oil stock tanks employed in the production sector.

There are an estimated 252,000 natural gas production wells and 575,000 crude oil wells in the United States. Most of these operations produce large volumes of relatively low-pressure gas, a large fraction of which is CH_4. This gas can be either disposed of (e.g., vented or flared), or recovered and used. According to two separate EPA methane emissions inventory estimates, about 30 billion cubic feet of methane is annually vented from crude oil storage tanks (EPA 1999, ICF 1997). This is the most significant source of vented emissions in the oil production sector, representing between 35 and 44 percent of total methane vented. Disposal options are relatively easy to implement and can reduce hazardous and toxic air pollutants. However, disposal options do not make use of the high energy content associated with the gas, produce large volumes of GHG and other emissions, and when flaring is used, can lower the aesthetic quality of communities and generate nuisance complaints. Many sites use vapor recovery units (VRUs) to capture hydrocarbon vapors that normally vent from production area oil storage tanks. VRUs are most often used when the recovered gases can be sold for the value of CH_4 (natural gas) and other hydrocarbons in the vapor.

COMM Engineering, USA (COMM), located in Lafayette, Louisiana, has requested that the GHG Center perform an independent verification of their Environmental Vapor Recovery Unit (EVRU™) at a gas and condensate production facility operated by TotalFinaElf E&P, USA, Inc. (TFE). The EVRU collects low-pressure vent gas from condensate storage tanks. The recovered gas is pressurized and injected into a natural gas pipeline for sale. The EVRU verification test will quantify gas recovery rate performance, total installed cost, and annual gas savings. The test will be conducted in partnership with EPA's Natural Gas STAR Program. The STAR Program, managed by the EPA Office of Air and Radiation (EPA-OAR), is a voluntary partnership between EPA and the oil and natural gas industry. The program has over 90 partner companies, which have committed to implement cost-effective technologies and to reduce CH_4 emissions. The EVRU verification will provide objective performance data to this industry group, as well as to the GHG Center's Oil and Gas Stakeholder Group.

This document is the Test Plan for verifying the EVRU performance. It contains the rationale for the selection of the verification parameters, verification approach, data quality objectives (DQOs), and Quality Assurance/Quality Control (QA/QC) procedures. The Test Plan will guide implementation of the test, creation of test documentation, data analysis, and interpretation.

This Test Plan has been reviewed by COMM, selected members of the GHG Center's Oil and Gas Stakeholder Group and STAR Partners, and the EPA QA team. Once approved, as evidenced by the signature sheet at the front of this document, it will meet the requirements of the GHG Center's Quality Management Plan (QMP) and thereby will satisfy the ETV QMP requirements. The final Test Plan will be posted on the Web sites maintained by the GHG Center (www.sri-rtp.com) and ETV program (www.epa.gov/etv).

Upon field test completion, the GHG Center will prepare a Verification Report and Statement (Verification Report), which will be reviewed by the same organizations listed above, followed by EPA-ORD management review. When this review is complete, the GHG Center Director and EPA-ORD Laboratory Director will sign the Verification Statement, and the final Verification Report will be posted on the GHG Center and ETV program Web sites. COMM will be provided written guidelines for the use of the ETV logo and use of the verification results to market the EVRU to potential customers.

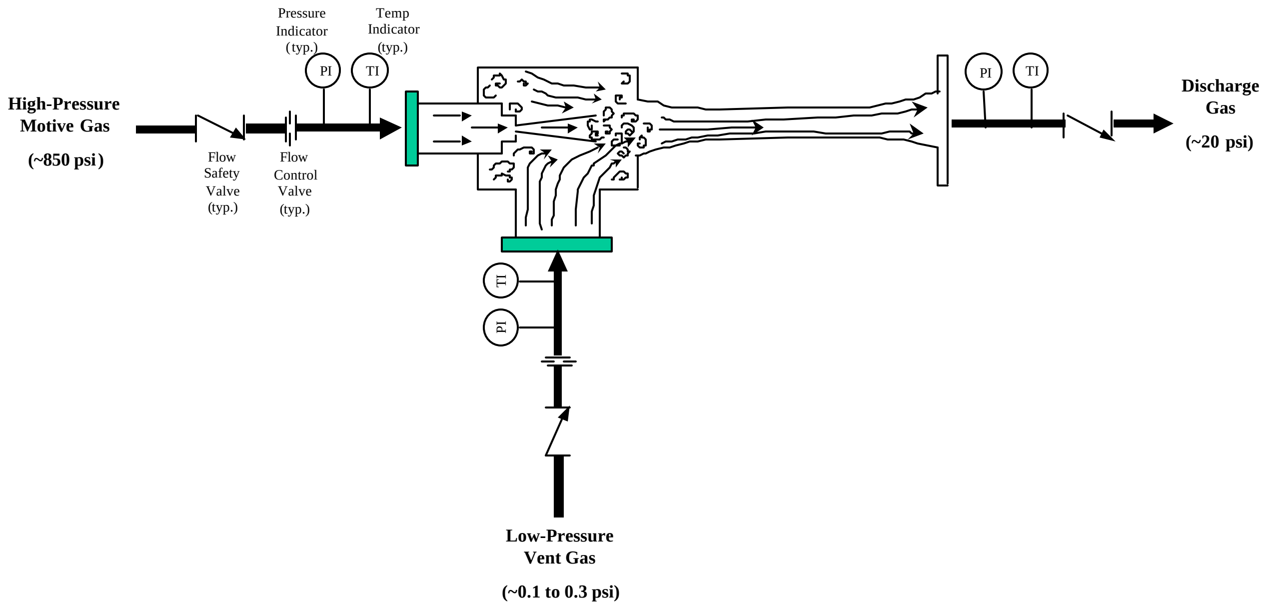
The remaining discussion in this section describes the EVRU technology. This is followed by a list of performance verification parameters that will be quantified through testing, and a description of the TFE facility. The section concludes with a discussion of key organizations participating in the verification, their roles, and a schedule of activities. Section 2.0 describes the technical approach for verifying each parameter including sampling, analytical, and QA/QC procedures. Section 3.0 identifies data quality assessment criteria for critical measurements and states the accuracy, precision, and completeness goals for each measurement. Section 4.0 discusses data acquisition, validation, reporting, and auditing procedures.

1.2 EVRU TECHNOLOGY DESCRIPTION

The EVRU is a non-mechanical eductor or a jet pump that is designed to capture low-pressure hydrocarbon vapors. High-pressure motive gas is used to entrain the low-pressure vapors. The combined gas stream exists at an intermediate pressure, which can be used on site as fuel or re-pressurized with a booster compressor to be injected into a natural gas transmission line for sale. It is a closed loop system designed to reduce or eliminate emissions of greenhouse gases (methane and carbon dioxide), volatile organic compounds (VOCs), hazardous air pollutants (HAPs), and other pollutants present in vent gas. It is applicable to hydrocarbon separation equipment that produce atmospheric vented gases in oil and gas production, processing, and transmission systems.

Figure 1-1 illustrates a schematic of the EVRU. It consists of an eductor system operating on the venturi principle as its core element. The system also includes flow safety valves, flow control mechanisms, pressure sensing devices, and temperature sensing and indicating devices. Pressure and temperature isolating valves (not shown) are also installed in the motive gas line entering the eductor for replacing or repairing EVRU components.

FIGURE 1-1. THE COMM EVRU



In operation, motive gas is supplied from the facility's existing dehydrated high-pressure (± 1,050 psig) natural gas. The motive supply pressure is regulated by a control valve. The motive gas flows through a venturi orifice situated in a mixing chamber, and creates a differential pressure within the EVRU jet pump. The mixing chamber has a port which allows low-pressure fluids to be drawn into the chamber due to the pressure differential created between the high-pressure motive line and the low-pressure vent line. The low-pressure vapors drawn into the eductor mixing chamber mix with the motive gas, resulting in a mixture of both fluids. The low-pressure line contains a valve to prevent back flow in the tanks. The ratio between pressure and volume of the mixed fluid is adjusted by controlling the motive gas volume and pressure with a flow control valve. The design ratio typically ranges from 1.75 to 2.0 parts motive gas to 1 part low-pressure vent gas.

The mixed fluid exits the eductor discharge line at a pressure less than the inlet motive gas but greater than the low-pressure gas being drawn into the mixing chamber. The gas can be discharged into the low-pressure separator inlet line of a water skimmer tank, a heater treater tank, and/or a first stage compressor for sale. The discharge line contains a pressure sensing device to determine the mixed fluid pressure departing the eductor, and a temperature sensing and indicating device to assist operators with the control of the mixed fluid departing the eductor. It also contains a flow safety device to prevent back flow and over-pressurizing of all components upstream of the flow safety device. Pressure and temperature isolating valves (not shown) are also provided in the discharge line for replacing or repairing the flow sensors.

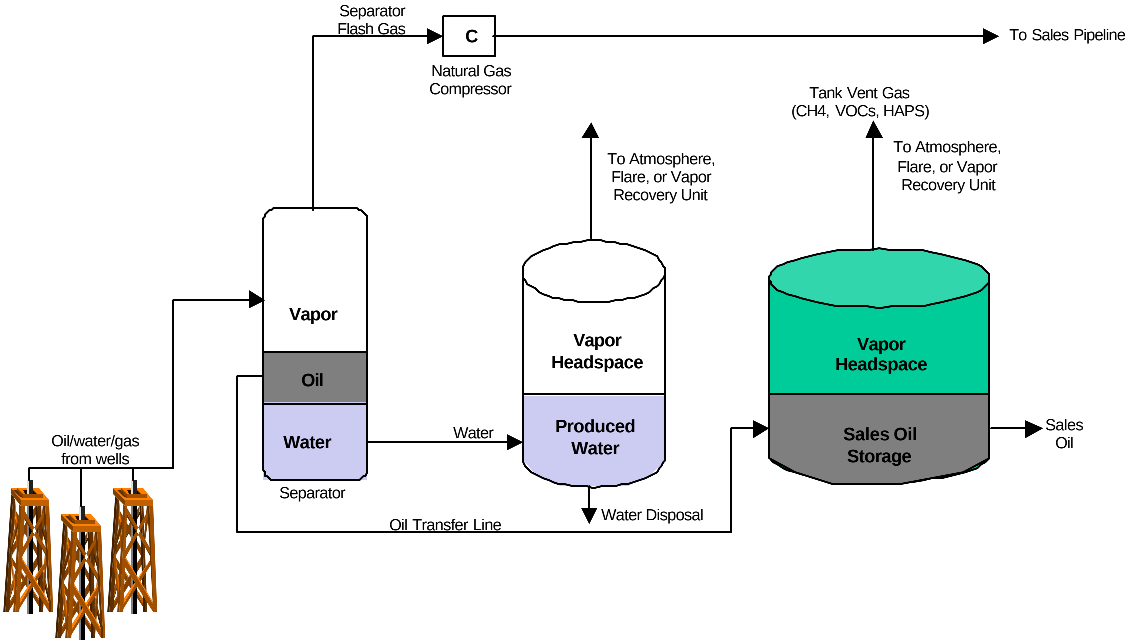
Depending on the volume of low-pressure gas to be recovered, additional eductor jet pumps may be installed in the EVRU system. When connected in series, the discharge line is connected to the inlet line of a succeeding jet pump prior to discharge back into a sales pipeline. When connected in parallel, several different sized jet pumps are brought on line depending on the available flow of low-pressure gas. This latter system will be employed at the TFE site.

1.3 TEST FACILITY DESCRIPTION

At typical oil and gas production facilities, operations begin with exploration to locate new sources of crude oil and natural gas. When potential sources are located, production wells are drilled into underground reservoirs, and the products are pumped to the surface. Domestic crude oil and natural gas (produced alone or in combination with crude oil) are transported to nearby processing stations where the products are processed to prevent corrosion and other problems in downstream handling and processing equipment (GRI 1994). The crude oil is transported from the fields to refineries by a complex network of pipelines, trucks, rail, barges, and tankers to make finished products (e.g., gasoline). The processed natural gas is pressurized and distributed to consumers via a network of gas transmission and distribution lines.

Figure 1-2 illustrates a simplified diagram of the oil/gas production and processing operation. A separator or a heater treater is first used to separate oil, gas, and water produced by the wells. Crude oil is heated to ensure good separation of the three phases at relatively low-pressure (20 to 60 psig). The low-pressure gas exiting the separator is routed to a gas dehydrator to remove excess water or directly to a field compressor which pressurizes the gas to pipeline sale pressure. The liquids from the separator are split into hydrocarbon and aqueous phases and routed to their respective tanks. The crude oil is stored in the tanks in order to stabilize flow between production wells and pipeline or trucking transportation sites. The water is also stored in tanks, and prepared for disposal.

Figure 1-2. Typical Oil and Natural Gas Production and Processing Operation



During storage, light hydrocarbons dissolved in crude-oil and some inert gases vaporize and collect in the space between the liquid level and the fixed roof of the tank (EPA 1999). As the liquid level in the tank fluctuates, vapors are expelled from the tank due to flashing, working, and breathing losses. The tanks are designed to operate near atmospheric pressures. As the hydrocarbon liquid is transferred from the separator to the tanks, its pressure is reduced from 60 psig to atmospheric pressure in the tank. This pressure drop causes some of the liquid hydrocarbons to flash into the vapor phase. During the filling operation, the pressure inside the tank increases as the liquid level rises and the tank pressure eventually exceeds the relief pressure setting. The vapors are expelled from the tank via a pressure relief vent (PRV). During the emptying operation, air is drawn into the tank as the liquid level decreases, and becomes saturated with organic vapor. This evaporation process expels vapors from the tank. In addition to flashing and working losses, breathing losses occur as a result of vapor expansion caused by daily changes in ambient temperature and pressure (i.e., without any liquid level change in the tank).

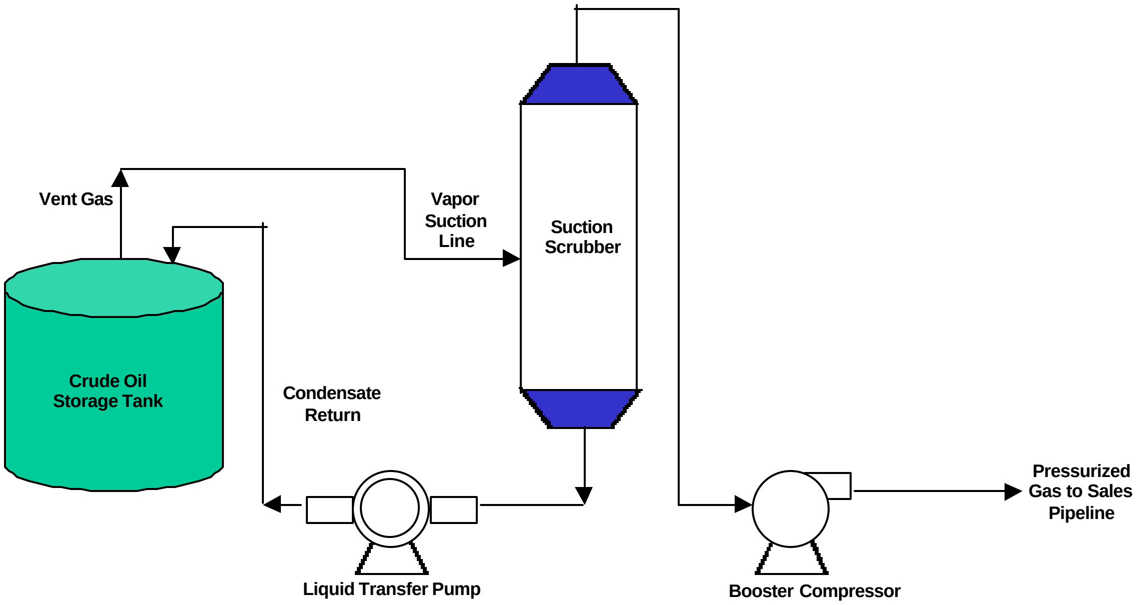
Although many factors affect vapors released from the tanks, the primary contributing factors are:

- oil production rate
- oil/gas composition
- vessel capacity
- gas separator operating conditions
- vapor pressure of the stored liquid
- atmospheric conditions at the tank location

The resulting vapors are typically combined into a common header and routed away from the tanks to be vented, flared, or used. The composition of the vapor varies, but the largest component is CH_4 (40 to 60 percent). CH_4 emissions from production tanks is estimated to be the largest CH_4 venting source in the oil industry (EPA 1999, ICF 1997). Other components include heavier hydrocarbons such as propane (C_3H_8), butane (C_4H_{10}), and ethane (C_2H_6), inert gases such as nitrogen (N_2) and carbon dioxide (CO_2), and hazardous air pollutants (HAPs). Benzene, toulene, ethylbenzene, and xylene are the four commonly found HAPs, collectively referred to as BTEX. Under the National Emission Standards for Hazardous Air Pollutants, existing and new storage vessels with the potential for flash emissions are required "to be equipped with a cover vented through a closed vent system to a control device that recovers or destroys HAP emissions with an efficiency of 95 percent or greater" (CFR Title 40 Part 63).

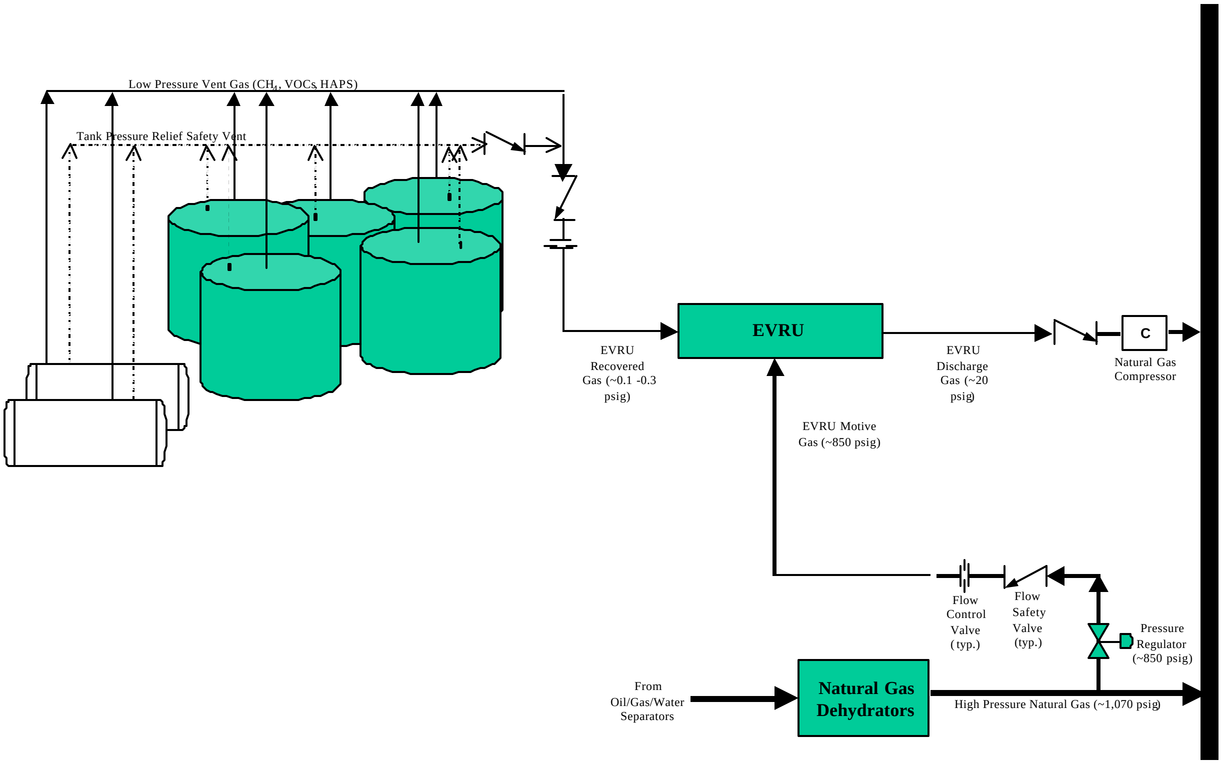
Tank vapors can be vented to the atmosphere, routed to a flare, or recovered by vapor recovery units (VRU). VRUs recover the vent gas stream as a saleable product by recompressing the vapors for addition to high-pressure sales lines. The test site currently uses a conventional VRU to recover vent gas from 5 crude oil stock tanks (400 barrels capacity) and 2 gun barrel tanks (750 barrels capacity). Figure 1-3 illustrates a schematic of a typical VRU process. Hydrocarbon vapors are drawn out of the tanks under low-pressure (about 0.125 psig), and are first piped to a separator (suction scrubber) to collect any liquids that condense. The liquids are recycled back to the storage tanks. From the separator, the vapors flow through a compressor that provides the low-pressure suction for the VRU system. The vapors are then metered and routed to a pipeline for sale. Gas recovery efficiencies of 90 to 98 percent have been reported for a typical VRU system (EPA 1995).

Figure 1-3. Simplified Diagram of a Typical VRU



The TFE test site employed a VRU, similar to that shown in Figure 1-3, to recover vapors from five fixed roof oil tanks and two gun barrel tanks. However, recurring mechanical failures in the existing VRU have resulted in periodic downtimes, lost product, increased operation and maintenance requirements, and higher emissions due to venting during downtime. For these reasons, the site has elected to replace the existing system with the EVRU. Figure 1-4 illustrates the EVRU system to be employed.

Figure 1-4. The COMM EVRU Installation at the Test Site



The TFE – El Ebanito site is an exploration and production (E&P) facility that handles separation of gas and condensate, gas compression, and gas dehydration from wells located within a 5-mile radius. It is located approximately 20 miles northwest of McAllen, Texas. In a typical year, daily condensate production rate ranges between 650 and 930 barrels per day.

A vent line from each tank carries the vapors to a common header to which the EVRU suction line is connected. The manifold and EVRU skid will be located near these tanks. A 6-inch diameter pipe connected to the gas manifold will convey the stock tank vapors to the EVRU's suction inlet. A 2-inch diameter pipeline will supply the motive gas from the dehydrator contact tower to the EVRU. The motive gas will be pipeline-quality natural gas at approximately 850 psig. A 4-inch diameter pipeline, operating at approximately 20 psig will convey the discharged vapors and motive gas to the facility's Ajax booster gas compressor, approximately 25 feet away. The Ajax compressor will pressurize the gas to the suction of the main three stage compressors and inject it into the sales pipeline.

The EVRU's primary purpose is to collect and transfer the vent gas for use. The quality of gas evolving from each stock tank varies according to many factors, including condensate production rate and composition, how long it stays in the tank (i.e., how frequently the inventory turns over), separator operating conditions, ambient temperature, and ambient atmospheric pressure.

The secondary purpose of the EVRU is to control the pressure in each stock tank due to pressure changes caused by flash gas being released from the stored condensate, and working and standing losses due to condensate transferring activities. Generally, the EVRU will maintain internal tank pressures at approximately 0.125 to 0.250 psia over local atmospheric pressure. This prevents atmospheric release of the gas through a pressure relief vent (PRV). The PRVs are designed to be activated when tank pressure exceeds approximately 4 oz (or 0.25 psi) pressure above atmospheric levels. Gas liberated from each tank's PRV is combined in a common header, which is connected to the EVRU suction line (Figure 1-4).

The volume of recoverable gas produced from condensate storage operations varies depending on condensate throughput, composition, operating conditions, tank duty cycle, and atmospheric temperature changes. For the test site, COMM has designed the EVRU to collect vent gas flows ranging between 69 and 208 scfm. It will consist of two (2) individual eductor units with capacities as follows:

Unit No.	Operation	Capacity
1	on continuously	200,000 scfd, 139 scfm
2	on/off as needed	100,000 scfd, 69 scfm
Unit 1 and 2 Combined	on/off as needed	300,000 scfd, 208 scfm

Depending on the amount of vent gas produced, pressure-operated controls will switch the individual units into or out of operation depending on need. For example, a given inventory of condensate may produce 69 scfm of flash gas, a capacity which would require a single EVRU. If new condensate arrived which produced 139 scfm, the stock tank pressure would rise. This would decrease the first EVRU's efficiency (i.e., a larger volume of motive gas would be required to move the same volume of vapors) and increase the possibility that the tank vent would open. The Number 1 unit will be the first on as pressure rises in the vessel. The Number 2 unit will turn on as pressure rises and turn off as the pressure decreases to the set point. If flash gas production were to spike to 208 scfm, the pressure controls would switch both units on, restoring the appropriate unit to operation when the spike ended.

1.4 PERFORMANCE VERIFICATION PARAMETERS

The verification parameters to be addressed are:

Gas Recovery Rate

The GHG Center will directly measure the flow rates of EVRU motive gas and EVRU discharge gas streams. The difference between the two readings will represent the flow rate of the gas recovered by the EVRU. Flow measurements will be conducted using integral orifice meters, sized to measure the range of gas flow rates expected during normal operations at the test facility. Continuous flow measurements data, averaged in 1-minute time increments, will be recorded for a minimum of one week.

The daily average gas recovery rate in standard cubic feet per day (scfd) will be reported for each 24-hour measurement period. The overall average gas recovery rate will also be reported for the verification period, and will represent the arithmetic average of the daily averages. It is anticipated that the individual daily average gas recovery rates will be normally distributed and fall within a range of values (confidence interval) around the mean. After one week of testing, a 90 percent confidence interval for the daily average results will be calculated. If the confidence interval is < 30 percent of the overall average gas recovery rate, it will be concluded that no significant flow variability is present that requires further characterization, and the test will be terminated. Alternatively, if significant trends are observed and the confidence interval exceeds the set criteria, testing will be extended to a maximum of 28 days.

Gas samples will be collected from the vent gas stream (i.e., EVRU suction) and the EVRU discharge stream, and analyzed in accordance with ASTM Method D1945 and GPA Method 2286 to determine CH_4, non-CH_4 hydrocarbons (NMVOC), and BTEX concentrations. Gas density and heating value analyses will be performed according to ASTM Method 3588. The discharge stream heating values will be used to assign an industry-accepted monetary value of the gas sold. A minimum of three gas samples will be collected for each week of field-testing. The proportion of CH_4 in the recovered gas times the daily average recovery rate will yield an estimate of the average daily CH_4 recovered.

Annual Gas Savings

The 1-minute gas recovery rate measurements (discussed above) will be used to determine the total volume of gas recovered by the EVRU over the verification period. It will be calculated as the integral of individual 1-minute flow rate measurements over the verification testing time or the area of a curve represented by flow measurements and time. The total gas recovered during the verification period will be reported in units of standard cubic feet (scf).

To estimate annual gas savings, the total gas recovered will be extrapolated for a period of 1 year following the verification period. The host site operator will be consulted to determine if it is reasonable to assume the oil production rate and other operating conditions that existed during field testing would persist for a year. If so, the total recovered gas will be extrapolated to yield an annual estimated gas savings in units of standard cubic feet per year (scfy). If significant changes in oil production, composition, and/or operating conditions are anticipated, annual gas savings will be estimated using trends observed during verification testing, and recommendations from the host site. Section 2.2 details the extrapolation procedures.

Value of Recovered Gas

To estimate the cash value associated with the annual gas savings, the annual cubic feet of gas saved will be multiplied by an industry-accepted price for natural gas (e.g., $2.25/Mcf). This will be the maximum savings expected with the EVRU. The natural gas price will be selected based on the measured heating value of the gas, and recommendations from the host site.

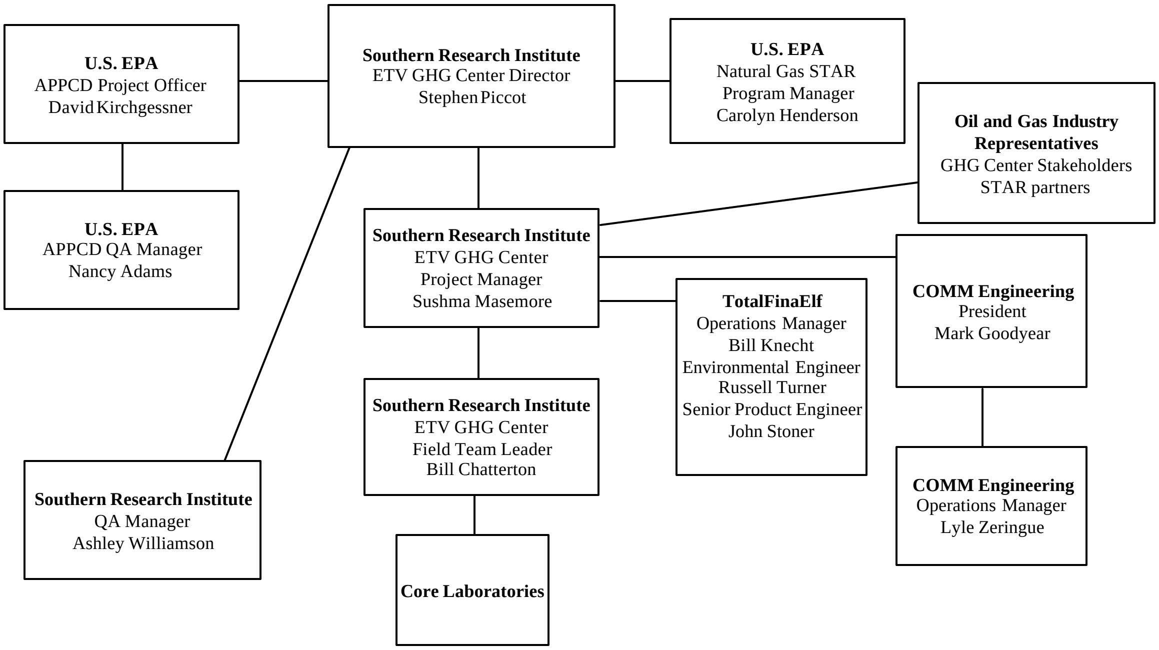
Total Installed Cost

The capital cost and installation cost of the EVRU will be verified for the test site. Capital costs will be verified by obtaining cost data from COMM and TFE, and will include all equipment and accessory items attributed to the installation. Labor hours associated with the installation, setup, and shakedown of the EVRU will be verified. The total installed cost reported will be the sum of the capital equipment, accessory items, and labor costs. Cost items that may not be associated with typical installation (i.e., optional equipment selected by TFE) will be identified by COMM, and documented in the Verification Report.

1.5 ORGANIZATION

Figure 1-5 presents the project organization chart. The following section discusses functions, responsibilities, and lines of communications for the verification test participants.

Figure 1-5. Project Organization



SRI's GHG Center has overall responsibility for planning and ensuring the successful implementation of this verification test. The GHG Center will ensure that effective coordination occurs, schedules are developed and adhered to, effective planning occurs, and high-quality independent testing and reporting occur.

The GHG Center's Ms. Sushma Masemore will have the overall responsibility as the Project Manager, under supervision of Mr. Stephen Piccot, the GHG Center Director. She will be responsible for overseeing field data collection activities of the GHG Center's Field Team Leader, including determination of data quality indicators (DQIs) prior to completion of testing. Ms. Masemore will follow the procedures outlined in Sections 2.0 and 3.0 to make this determination, and she will have the authority to repeat tests as determined necessary to ensure that DQOs are met. Should a situation arise during testing that could affect the health or safety of any personnel, Ms. Masemore will have full authority to suspend testing. She will also have the authority to suspend testing if quality problems occur. In both cases, she may resume testing when problems are resolved. Ms. Masemore will be responsible for maintaining communication with COMM, TFE, EPA, and stakeholders.

Mr. Bill Chatterton will serve as the Field Team Leader, and will support Ms. Masemore's data quality determination activities. The Field Team Leader will provide field support activities related to all measurements and data collected. He will install and operate the measurement instruments, collect gas samples, and ensure that QA/QC procedures outlined in Section 2.0 are followed. He will submit all results to the Project Manager, such that it can be determined that the DQIs for gas recovery rate, gas composition, and heating value are met. He will be responsible for ensuring that performance data collected by continuously monitored instruments and manual sampling techniques are based on procedures described in Section 4.0. The Field Team Leader will also monitor the installation of the EVRU such that actual installed cost is documented.

SRI's Quality Assurance Manager, Dr. Ashley Williamson, will review and approve this Test Plan. He will also review the results from the verification test, and conduct an Audit of Data Quality (ADQ), described in Section 4.4.3, and a Technical Systems Audit (TSA), described in Section 4.4.4. Dr. Williamson will report the results of the internal audits and corrective actions to the GHG Center Director. The results will be used to prepare the Verification Report.

Mr. Lyle Zeringue, Operations Manager, will serve as the primary contact person for COMM. He will provide technical assistance and coordinate installation and operation of the EVRU at the test site, and will be present during the first week of verification testing. Mr. Zeringue will coordinate with the TFE field operations engineer to ensure the unit and host site are available and accessible to the GHG Center for the duration of the test. Mr. Zeringue will also submit the capital equipment cost for the EVRU. COMM President, Mr. Mark Goodyear, will direct his activities. COMM will ensure safe operation of the unit and demonstrate necessary safety features, and provide on-site support as needed to accomplish the goals of the verification testing. COMM will review the Test Plan and Verification Report and provide written comments.

TFE will provide access to the test site during verification testing. TFE will assist in developing a cost estimate of the EVRU. This will include a review of capital and installation cost estimates submitted by COMM, and provision of the labor hours expended in the installation process. For the last three weeks of testing, when GHG Center personnel are not scheduled to be present on site, TFE will collect gas samples (three per week) for compositional analyses. TFE will also review the Test Plan and Verification Report and provide written comments.

The EPA Natural Gas STAR Program Manager is co-funding the EVRU verification along with the GHG Center. Ms. Carrie Henderson will review and comment on the Test Plan and Verification Report. The GHG Center stakeholder members and STAR Partners (one each) will also be invited to review the two documents. These industry peer-reviewers will advise the GHG Center on the selection of verification factors and provide guidance to ensure that the overall verification is based on recognized and reliable field measurement and data analysis procedures acceptable to industry and other stakeholders. The individuals will also support the wide distribution of the final verification results.

EPA ORD's Air Pollution Prevention and Control Division (APPCD) will provide oversight and QA support for this verification. The EPA-APPCD Project Officer, Dr. David Kirchgessner, is responsible for obtaining final approval of the Test Plan and Verification Report. The EPA QA Manager reviews and approves the Test Plan and Verification Report to ensure they meet the GHG Center QMP requirements and represent sound scientific practices.

1.6 SCHEDULE

The tentative schedule of activities for testing the EVRU is as follows:

Verification Test Plan Development

GHG Center Internal Draft Development	January 28 – February 28
Vendor and Host Site Review/Revision	March 1 – March 8
EPA and Industry Peer-Review/Revision	March 9 – April 12
Final Posted	April 25

Verification Testing and Analysis	
Measurement Instrument Installation/Shakedown	June 3 – June 7
Field Testing	June 10 – June 21
Data Validation and Analysis	June 24 – July 19
Verification Report Development	
GHG Center Internal Draft Development	July 1 – July 26
Vendor and Host Site Review/Revision	July 29 – August 2
EPA and Industry Peer-Review/Revision	August 5 – August 16
Final Posted	August 31

2.0 VERIFICATION APPROACH

2.1 OVERVIEW

The measurement strategy for the four verification parameters is discussed as follows:

- Gas Recovery Rate (Section 2.2)
- Annual Gas Savings (Section 2.3)
- Value of Gas Recovered (Section 2.4)
- Total Installed Cost (Section 2.5)

Each subsection discusses the analytical approach and measurement instruments to be used. Data quality assessment criteria are discussed in Section 3.0.

2.2 DETERMINATION OF GAS RECOVERY RATE

On June 29, 2001, COMM collected preliminary measurements on the vent gas manifold to determine the level of gas flows expected and design the EVRU system for the site-specific conditions. An ultrasonic meter was used to measure 1- minute average vent gas flow rates and vent gas temperatures for a 24 hour period. Also during this time, TFE operators collected a single gas sample and submitted it for compositional analysis to their contract laboratory. The flow rate measurements data are displayed in Figure 2-1, and the compositional data are summarized in Table 2-1. Typical of many facilities of this type, vent gas flow rates and compositions are not continuously monitored at the host site. The GHG Center has used the preliminary measurements data to select and specify verification instruments.

Figure 2-1. Preliminary Measurements of Daily Vent Gas Flow Rates at the Test Site
(Based on 1-minute data collected by COMM on June 29, 2001)

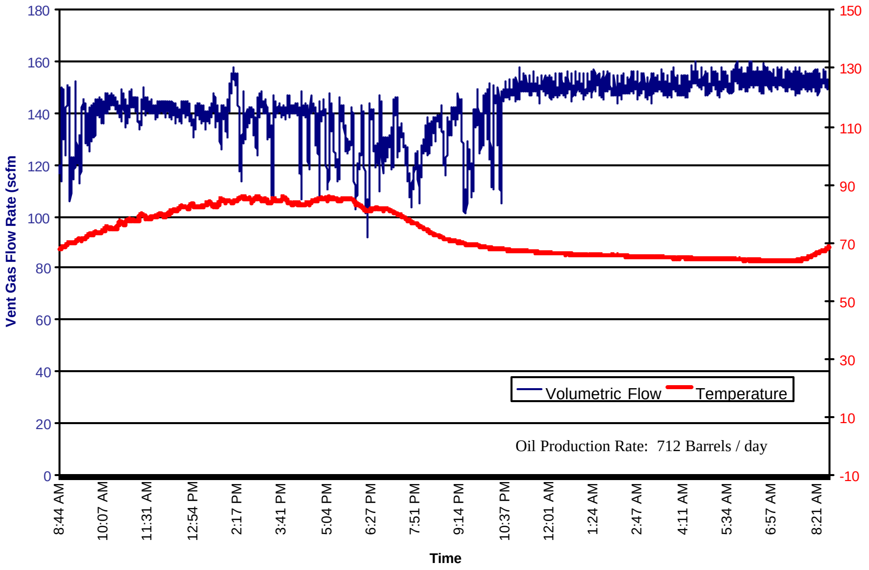


Table 2-1. Preliminary Analysis of Vent Gas Composition at the Test Site
(Based on a single grab sample collected by TFE on June 29, 2001)

Component[a]	Mole Percent	Mole Fraction	Weight Fraction	lbs/hr
Nitrogen	0.0630	0.0176	0.0006	0.39
Carbon Dioxide	0.1240	0.0546	0.0017	1.21
Methane	56.9030	9.1289	0.2849	202.91
Ethane	12.2330	3.6785	0.1148	81.76
Propane	10.3810	4.5777	0.1429	101.75
n-Butane	4.8480	2.8178	0.0879	62.63
Iso-Butane	4.5490	2.6440	0.0825	58.77
N-Pentane	2.1800	1.5729	0.0491	34.96
Iso-Pentane	2.9920	2.1587	0.0674	47.98
Iso-Hexanes	2.4800	2.1372	0.0667	47.50
Heptanes	3.2470	3.2558	0.1016	72.37
Octanes	< 0.0000	< 0.0000	< 0.0000	< 0.00
Nonanes	< 0.0000	< 0.0000	< 0.0000	< 0.00
Decanes	< 0.0000	< 0.0000	< 0.0000	< 0.00
Total	100.000	Molecular Weight = 32.0438		

[a] Compositional analyses for N-Hexane, Benzene, Toluene, Ethylbenzene, Xylenes, and Trimethylpentane components were not made. Based on industry literature, the concentrations are expected to be in ppm levels.

As shown in Figure 2-1, individual 1 minute average vent gas flow rates ranged between 95 and 160 scfm. The site was producing oil at 712 barrels per day (bpd) and the separator pressure was operating at about 50 psig. This equates to between 192 and 324 scf gas vented per barrel oil produced (scf/bbl), defined as the flash gas factor. The flow meters to be used in the verification must accommodate this vent gas flow range.

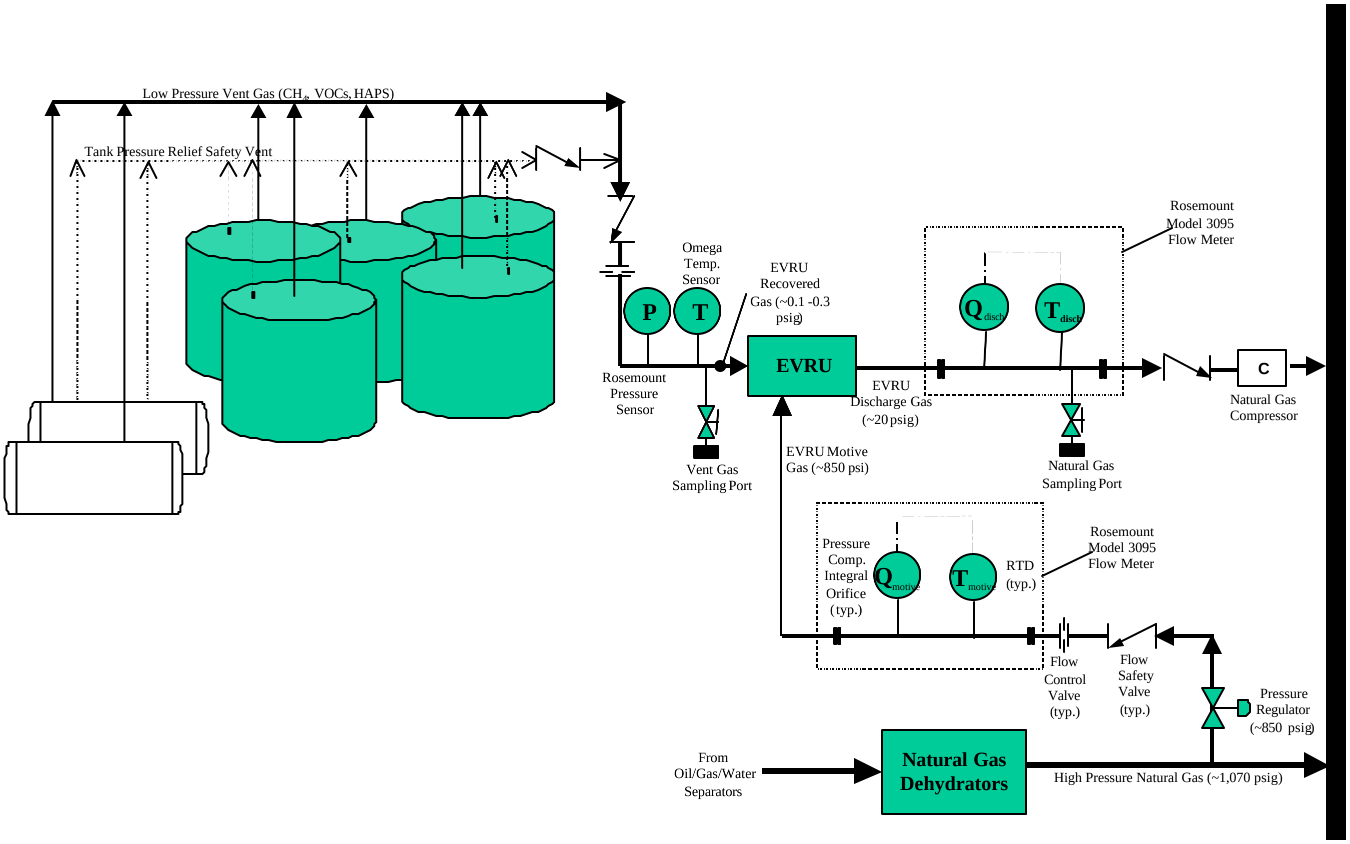
The flow meters must also accommodate potential variability in gas flows due to changes in key operating conditions. According to site operators, the condensate throughput can fluctuate between 650 and 930 bpd. Since flash gas is likely to be the largest loss at the test site, changes in production levels will directly affect the volume of gas vented from the storage tanks (assuming other conditions such as oil/gas composition and separator pressures remain unchanged). Based on the measured flash gas factor, it is expected that between 87 and 210 scfm gas will be vented at the range of production rates expected at the site. The flow meters to be used in the verification are sized to accommodate the following flow ranges in vent gas, motive gas, and discharge gas rates.

Table 2-2. Expected Gas Flow Rates and Pressures

Gas Stream	Flow Rate (scfm)	Pressure (psig)
Vent Gas	80 - 220	0.12 - 0.25
Motive Gas	176 - 484	850
Discharge Gas	256 - 704	20

Direct measurement of the vent gas flow rate into the EVRU is difficult and expensive due to the low vent gas pressure and low gas velocity. In this verification, the GHG Center will directly measure motive gas and discharge gas flow rates. The difference between the two measured values is the vent gas flow rate into the EVRU, and will represent the EVRU gas recovery rate verification parameter. Figure 2-2 illustrates a schematic of the measurements system.

Figure 2-2. Schematic of the Measurement System



The motive and discharge gas flow rate sensors produce continuous analog (4 to 20 mA) outputs. The GHG Center's data acquisition system (DAS) will poll each sensor once per second and compute 1-minute average values for each parameter. The DAS will record the 1-minute averages into a time-stamped database. Section 4.1 describes the DAS and its operations. The 1-minute average gas recovery rate will be:

$$Q_{recovered,i} = Q_{disch,i} - Q_{motive,i} \qquad \text{(Eqn. 1)}$$

Where:

$Q_{recovered,i}$ = Gas recovery rate for minute i, scfm
$Q_{disch,I}$ = Discharge gas flow rate for minute i, scfm
$Q_{motive,I}$ = Motive gas flow rate for minute i, scfm

As shown in Figures 1-1 and 2-1, Q_{disch} is larger than Q_{motive} and $Q_{recovered}$. It is the sum of motive gas flow and recovered gas from vent stream.

Daily average gas recovery rate will be computed as the mean of the 1-minute average gas recovery rates for each full day of verification testing as follows:

$$Q_{recovered, daily\ avg} = \left(\frac{\sum_{i=1}^{n} Q_{recovered,i}}{n} \right) 1440 \qquad \text{(Eqn. 2)}$$

Where:

$Q_{recovered,\ daily\ avg}$ = Average daily gas recovery rate, scfd
N = Number of 1-minute values per day
1440 = Minutes per day

The Verification Report will present the daily average, maximum, and minimum values for each full day of testing.

To determine overall average methane and BTEX recovery rate, vent gas samples will be manually collected in stainless steel canisters and submitted to Core Laboratories for compositional analysis. A minimum of three gas samples per week will be collected. The overall daily average gas recovery rates, determined in Equation 3, will be multiplied by the average methane and BTEX concentrations to determine the recovery rates for each compound (scfd CH_4 and scfd BTEX).

Duration of Testing:

Individual daily averages will fall within a range of values (confidence interval) around the mean of all daily values. Confidence intervals include an estimate of the proportion of test results expected to fall within the given interval. The confidence interval size depends on the sample standard deviation. For a given sample standard deviation, which is a measure of the data's variability, a larger number of daily averages will tend to reduce the size of the confidence interval. For a data set with a large standard deviation (i.e., widely varying average daily gas recovery rates), even a large number of tests cannot reduce the size of the confidence interval below certain limits. The GHG Center must strike a balance between determining average values with a reasonable confidence interval and conducting a verification that is affordable to the vendor and the ETV program.

Based on the GHG Center's experience in testing process equipment under actual field conditions, and based on a review of actual vent gas data compiled by API and GRI for sites in the United States, it is reasonable to expect that 90 percent of the daily average gas recovery rates will fall within 0.30 times the mean value.

The GHG Center will determine overall average gas recovery rate for one week of testing, as shown in Equation 3. If 90 percent of the individual daily average results are within 0.30 times the weekly averages, testing will be concluded. For example, if the overall average recovery rate is 100 scfd, 90 percent of the daily average results should be between 70 and 130 scfd. If the individual daily averages are not within the stated interval, this can imply a larger variability due to crude oil flash gas rates, process conditions, or other factors. In this case, the GHG Center will continue sampling and determine more daily averages. After each additional day of testing, the overall confidence interval will be recomputed until it is < 0.30 times the overall mean or until 28 days have elapsed.

$$Q_{recovered,\ overall\ avg} = \frac{\sum_{i=1}^{d} Q_{recovered,dailyavg}}{d} \qquad \text{(Eqn. 3)}$$

Where:

$Q_{\text{recovered, overall avg}}$ = Overall average daily gas recovery rate, scfd
D = Number of days of testing

The confidence interval depends on the sample standard deviation and the number of test runs, or in this case daily average values, conducted as follows:

$$e = t_{.05,n-1}\left(\frac{s}{\sqrt{n}}\right) \qquad \text{(Eqn. 4)}$$

Where:

E = Half-width of the 90 percent confidence interval; target value is < (0.30) ($Q_{\text{recovered, overall avg}}$)
$t_{.05,n-1}$ = 90 percent T distribution value (Table 2-3)
s = Sample standard deviation
n = Number of daily average values

Table 2-3. Selected 90 % T Distribution Values

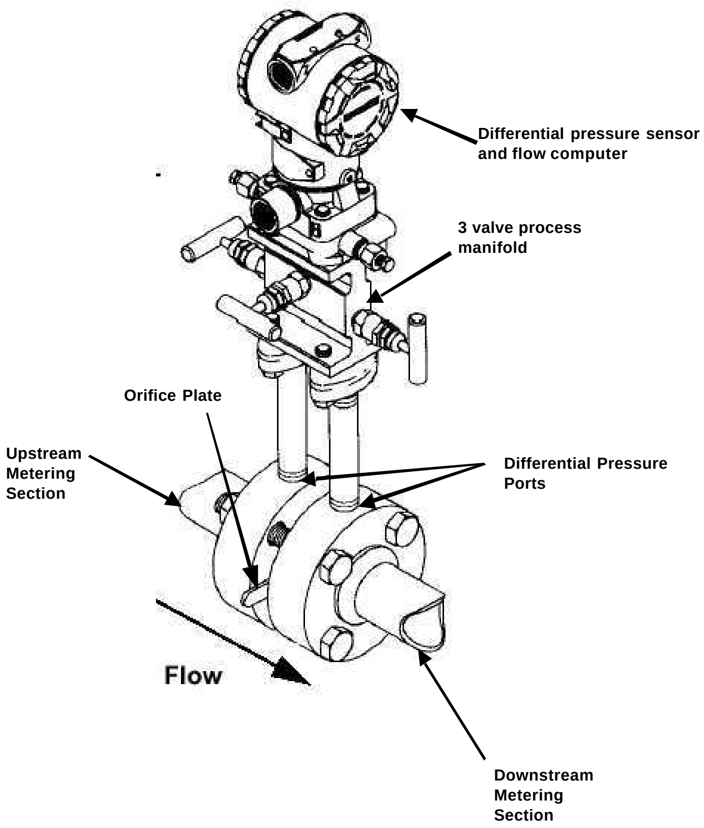
n	$t_{.05,n-1}$
7	1.895
8	1.860
9	1.833
10	1.812
11	1.796
12	1.782
13	1.771
14	1.761
15	1.753
16	1.746
17	1.740
18	1.734
19	1.729
20	1.725
21	1.721
22	1.717
23	1.714
24	1.711
25	1.708
26	1.706
27	1.703
28	1.701

The following subsections discuss the instruments and/or equipment to be used for gas flow measurements, gas composition and heating value measurements, and process conditions monitoring.

2.2.1 Gas Flow Rate Measurements

The GHG Center will determine motive gas and discharge gas flow rates with separate Rosemount Model 3095 mass flow meters installed on each pipe run. Figure 2-3 shows the major components of the flow meter.

Figure 2-3. Rosemount Flow Meter Components



The flow meter measures differential pressure developed across an orifice by the flowing gas. The flow meter's computer uses the differential pressure combined with gas density, compressibility, temperature, pressure, orifice discharge coefficient, metering section area, and other factors to calculate the standard compensated flow rate in standard cubic feet per minute (scfm). Gas industry standard conditions for compensated flow are 60 ^{o}F, 14.7 psia. A Rosemount Series 68 resistance temperature detector (RTD) installed in a 0.5-inch NPT tap in the gas pipeline will monitor the gas temperature; a short cable connects this sensor to the gas flow meters. The flow meter response time to a step change in flow is 0.2 second. Each flow meter will provide analog 4 to 20 mA signals to the DAS. Table 3-3 lists the instrument ranges, accuracy, and expected operating ranges.

Both meters will be factory calibrated with National Institute for Standards and Technology (NIST) traceable standards. Rosemount certifies that the motive gas and discharge gas flow meter accuracy is ± 1.0 and ± 1.5 percent, respectively. Section 4.1 describes the DAS, its scan times, and how it will compute and record average flows. Appendix B-1 provides setup checklists and standard operating procedures for the flow meters.

The 850 psig motive gas metering orifice will be 0.661-inch in diameter, and the 20 psig discharge gas metering orifice will be 1.334-inches in diameter. Custom-built metering sections house the orifice plates and differential pressure ports. The distance to upstream and downstream disturbances in each metering section will conform to Rosemount's specifications. Both the motive gas and discharge gas metering sections will be 2-inch diameter pipe. The metering sections are designed to directly replace corresponding lengths of the motive gas and discharge pipelines. ANSI flanges at each end of the metering sections allow them to be bolted into the appropriate pipeline. Test facility personnel will install the metering sections under the supervision of the Field Team Leader.

Each flow meter will be configured using Rosemount Engineering Assistant (EA) software program. It will be accessed via a HART protocol serial modem connected to a lap top computer. The EA software allows users to program gas composition directly into the meter, enabling compensated flow algorithms within the software to calculate compressibility factors at actual gas conditions (i.e., measured gas pressure and temperature). The algorithms are based on compressibility factors developed by the American Gas Association (AGA), and are a function of the molar volume of each compound present in the gas stream, gas pressure, and gas temperature (AGA 1992, AGA 1994). The natural gas industry uses these procedures to calculate compensated flows with orifice meters in custody transfer applications.

Table 2-4 summarizes the composition of a single vent gas sample collected by TFE during a preliminary survey conducted by COMM (shown earlier Table 2-1). The table also lists motive gas compositions expected for the test site (based on analysis performed by TFE on the natural gas sales line). Their combined effects on the discharge gas composition, based on EVRU design ratio of 1.75 volume of motive gas to 1.00 volume of vent gas, indicate that the diluted discharge gas composition is well within the range allowed in the AGA 8 database for compensated flow calculations. This means that if these gas compositions are measured during the verification test, the Rosemount flow meter will be computing compressibility factors and reporting flow rates that are consistent with AGA standards.

Table 2-4. Target Gas Compositions for the Test Site

Compound	Motive Gas Composition [a] (Volume %)	Vent Gas Composition [b] (Volume %)	Discharge Gas Composition [c] (Volume %)	AGA-8 Allowable Range [d] (Volume %)
Methane	88.284	56.903	76.87	0 - 100
Ethane	6.802	12.233	8.78	0 - 100
Propane	2.411	10.381	5.31	0 - 12
Butanes	1.171	9.397	4.16	0 - 6
Pentanes	0.440	5.172	2.16	0 - 4
Hexanes	0.658	2.480	1.32	0 – dewpoint
Heptanes	--	3.247	1.18	0 – dewpoint
Nitrogen	0.080	0.063	0.07	0 - 100
Carbon Dioxide	0.154	0.124	0.14	0 - 100

[a] Based on sales gas analysis performed by TFE on June 10, 2001
[b] Based on analyses of vent gas sample collected by TFE on June 29, 2001
[c] Estimated based on discharge gas mixture consisting of 1 part vent gas and 1.75 parts motive gas
[d] Represents the range specified in AGA-8 for compressibility determinations in compensated flow calculations

Prior to initiating the verification test, each flow meter must be programmed with expected motive gas and discharge gas compositions. The following paragraphs discuss the strategy for defining initial compositions for the two flow meters.

Motive gas composition is expected to be consistent throughout the verification test because its source will be the sales quality natural gas, suitable for custody transfer. Actual motive gas composition for the test period will be obtained from on-site natural gas analyses performed by TFE operators once per month. The Field Team Leader will program the motive gas flow meter with the most recent gas analysis data prior to the start of testing.

Discharge gas composition will vary depending on the vent gas composition and the motive gas/vent gas mixture ratio. The GHG Center plans to directly measure discharge gas composition before and during field testing. Prior to initiating the verification test, the Field Team Leader will collect a minimum of two gas samples per day for three continuous days. The samples will be collected from the EVRU discharge port, and shipped to a laboratory for compositional analysis (discussed later in Section 2.2.2.). The data will be reviewed to assess variability from day to day, and as a function of the time of day. The average composition will be computed, and entered into the discharge gas flow meter software. This will represent the baseline gas composition upon which discharge gas flow rates are computed by the flow meter, and reported in the DAS.

During the test, the GHG Center will request TFE operators to collect a minimum of three discharge gas samples per week, and submit them to the laboratory for compositional analysis. Actual discharge gas composition will not be programmed into the EA software after testing starts because the lab results will not be made available for 10 to 14 days after the samples are collected. The effects of changes in gas composition on the data quality of flow measurements are not described here, but are discussed in Section 3.2.

2.2.2 Gas Composition and Heating Value Analyses

Gas composition analyses will be conducted on the gas recovered by the EVRU and the discharge gas supplied to the sales pipeline (Figure 2-2). Concentrations of CH_4, VOC, HAPs, gas density, and gas higher and lower heating value (HHV and LHV) will be determined. Compositional results of the vent gas stream will be used to determine CH_4 and BTEX recovery rates. The compositional data from the discharge line will serve two primary functions. The first is to use the gas composition to properly configure the Rosemount orifice gas flow meter as described earlier. The second function is to quantify the heating value of the gas supplied to the sales pipeline, such that an industry accepted natural gas sales price can be selected, and the value of the recovered gas can be determined.

The gas samples will be collected from an access port in the vapor gas manifold (upstream of the EVRU) and on the discharge line of the EVRU (Figure 2-2). The port is downstream of a ball valve and consists of a 0.25-inch NPT union. Samples will be manually collected in stainless steel canisters provided by the analytical laboratory - Core Laboratories, Inc. of Houston, Texas. The canisters are pre-evacuated 600-mL vessels with valves on the inlet and outlet sides. Prior to sample collection, canister pressure will be checked using a vacuum gauge to document that the canisters are under vacuum and are therefore leak free. Condensation of moisture or hydrocarbons in the canister after sample collectin can cause a low bias on BTEX analysis (GRI 1995). Maintaining a vacuum in the canister at all times minimizes the possibility of condensation in the canister. Therefore, a vacuum of at least 5 inches Hg will be left on each vent gas sample during collection. Canisters that are not fully evacuated upon receipt from the laboratory will not be used for testing. During testing, the connections between the canisters and the fuel sampling port will be screened with a hand-held hydrocarbon analyzer or screening soap to check for leaks in the system. Leaks will be corrected prior to sampling. Appendix A-2 contains detailed sampling procedures that will be followed; Appendices A-3 and A-4 contain sampling log and chain of custody forms.

Gas compositional analysis will be conducted at the laboratory in accordance with American Society for Testing and Materials (ASTM) Specification D1945 for quantification of speciated hydrocarbons including methane (C1) through pentane (C5), heavier hydrocarbons grouped as hexanes plus (C6+), nitrogen, oxygen, and carbon dioxide (ASTM 2001a). In addition, Gas Processors Association (GPA)

Method 2286 will provide an extended analysis to speciate the C6+ compounds [C7 through C12 and benzene, toluene, ethyl benzene, and xylene (BTEX) (GPA 2000)]. Total VOC is defined as the sum of all gas components listed above less the methane content. Total HAPs is defined as the sum of the organic compounds quantified using the above referenced analytical methods that are listed as regulated HAPs in CFR Title 40, Part 63, Subpart F. These include benzene, toluene, ethylbenzene, xylene, and hexane.

During analysis, sample gas is heated to the gas temperature recorded during collection and injected into a gas chromatograph (GC) equipped with a molecular sieve column and a thermal conductivity detector. Components are physically separated on the columns and the resultant areas under the chart trace are determined for each compound. These areas are compared to the areas of the same compounds contained in a calibration reference standard that is analyzed under identical conditions. The reference standard areas are used to determine instrument response factors for each compound, and these factors are used to calculate the component concentrations in the sample.

GPA Method 2286 is essentially an extension of the ASTM D1945 procedures that uses additional chromatographic columns to separate heavier hydrocarbons. After injection into the GC, the sample is split into three sections. The first section separates and detects oxygen, nitrogen, and methane using the thermal conductivity detector reference above. The second section separates methane through normal pentane using a different column and a flame ionization detector (FID). The third section separates and quantifies iso-pentane through tetradecane using a third column and a second FID. Consistent with the calibration procedures specified in ASTM D1945, analytical response factors for each compound are established by analyzing a calibration reference standard under identical conditions. An HP 339611 integrator acquires the analysis data.

Instrumentation is calibrated weekly with the reference standards as a continuous calibration check. During calibrations, the analytical response factors generated for each compound analyzed are programmed into the instrument. Instrument accuracy is ± 0.02 percent full scale, but allowable method error during calibration is ± 1 percent of the reference value of each gas component. The instrument is re-calibrated whenever its performance is outside of the acceptable calibration limit of ± 1 percent for each component. Calibration records will be obtained and reviewed by the GHG Center. Records of the gas calibration standards will also be obtained. Examples of gas analysis report and instrument calibration data are presented in Appendices A-5 and B-3, respectively. These examples are for normal pipeline quality natural gas composition. Actual samples collected during this verification will also include the extended analysis for BTEX and C7 through C12 compounds.

Additional QA/QC checks that will be conducted include duplicate analyses of the same sample by the laboratory and analysis of a blind audit sample of a natural gas standard supplied by the GHG Center. These procedures are detailed in Section 3.5.2 where the repeatability results of the duplicate analyses are introduced as the primary data quality indicator parameter for gas composition.

The laboratory will use the compositional data to calculate the gross (HHV) and net (LHV) heating value, and the relative density of the gas per ASTM Specification D3588 (ASTM 2001b). The data quality of the heating value determinations is related to the repeatability of the ASTM Specification D1945 analysis. The analytical repeatability is defined as the difference between two consecutive results obtained by the same operator with the same apparatus under constant operating conditions. Provided the analytical repeatability criteria are met, Specification D3588 provides the equations that are used to calculate repeatability of the LHV calculations. The repeatability expected for duplicate samples is approximately 1.2 Btu/1000 ft^3, or about 0.1 percent.

2.2.3 Process Operating Conditions

It is expected that users of the EVRU will be interested in knowing the process conditions during which the verification test data were collected so that they can determine the applicability of the results to their sites. The users may also be interested in potential impacts (positive and negative) the EVRU can have on storage tank pressures. To address these data requirements, the GHG Center plans to document key process operating conditions throughout the verification test. This includes: crude oil production rate, separator pressure, vent gas pressure and temperature, and ambient temperature. Table 2-5 summarizes the source of data and other monitoring requirements.

Table 2-5. Process Operating Conditions

Measurement	Units	Source	Method of Recording	Frequency of Measurements
Oil Production Rate	barrels oil / day	Site logs of daily production rate	Obtain copies of site logs	Daily logs
Separator Pressure	psig	Site logs or pressure gauge on separator	Obtain copies of site logs or record from gauge readout	Minimum of 2 times per week
Vent Gas Pressure	psig	Instruments installed by GHG Center	Logged on GHG Center DAS	1-minute averages from 1-second readings
Vent Gas Temperature	^{o}F			
Ambient Temperature	^{o}F			

2.2.3.1 Oil Production Rate

Daily oil production rates will be used to assess potential trends in gas recovery rates as a function of crude oil throughout. The data will also be used to extrapolate the total gas recovered for one year of operation (discussed in Section 2.3) using flash factors observed during testing. It is also anticipated that users of the EVRU technology will apply the oil production data to determine applicability to their sites.

Oil production rate as barrels per day will be documented using daily logs maintained by station operators at the site. Appendix A-9 contains the log form.

2.2.3.2 Separator Pressure

In addition to oil production rate, emissions resulting from flashing are also influenced by the change in pressure to which the entrained gases are subjected. As discussed earlier, the largest pressure change is due to the transfer of crude oil from high-pressure separator system to the atmospheric storage tanks. Assuming all operating conditions are equal (i.e., production rate, composition, separator temperature), the greater the pressure drop, the greater the gas volume released per barrel of oil produced (Boyer and Brodnax 1996). In a recent EPA report that estimated CH4 emissions from the petroleum industry, flash gas can increase by a factor of 2 when the separator pressure increases from 20 psig to 40 psig, and by a factor of 3 when the separator pressure changes from 20 to 60 psig (EPA 1999).

Due to the potential impact a gas separator can have on vent gas volumes, the GHG Center will obtain records of separator operating pressures from site logs or by noting the pressure gauge readout on the separator system. The data may be used to develop potential trends in gas recovery rates as a function of separator pressures. Appendix A-9 contains the log form.

2.2.3.3 Vent Gas Pressure

The EVRU is designed to control the internal tank pressures at approximately 0.125 to 0.250 psig (i.e., 0.125 to 0.250 psia above local atmosphere pressure. In the event the EVRU is unable to meet the design pressures, the tank will begin to pressurize, and when the pressure exceeds a set pressure of 0.250 psig, gas will be rejected through a pressure relief valve (PRV). During such events, the common vent header connected to the EVRU suction line, will register consistent, elevated pressure readings, indicating the system has reached its maximum capacity.

Storage tank pressure is not monitored by the facility. However, since the tanks are vented through a common header, that header will provide a reliable indication of the pressure in the tanks. Vent gas pressure will be monitored with a pressure transducer at a rate of one reading per second. A Rosemount model 3051 smart pressure transmitter will be used, which has a high degree of stability over time (0.25 percent in five years). Prior to installation in the field, the meter will be factory-calibrated by Rosemount and laboratory-calibrated by the GHG Center using an inclined oil manometer (primary standard). Laboratory calibration will include the range of pressures expected in the field (0- to 10-inches of water, or 0 to 0.361 psig). Routine quality control consists of daily checks for reasonableness, trends, spikes, or other changes in operation that could indicate a system or sensor problem.

The vent gas pressure transmitter will provide 4 to 20 mA continuous analog signals to the DAS, which will log 1-minute average data from 1-second readings.

2.2.3.4 Vent Gas Temperature

Vent gas temperature data are needed to select the actual temperature at which vent gas samples are collected for compositional analysis. Gas analyses will be performed at these temperatures to enable more accurate representation of methane and BTEX levels. That is, each compound will volatilize differently at different temperatures, and thus its emission levels recovered by the EVRU will be more representative of actual conditions. The analytical laboratory will be required to heat the gas canisters to these temperatures, and perform compositional analyses as described earlier.

Vent gas temperature will be monitored using an Omega type K thermocouple and Model TX-93 4 to 20 mA current signal transmitter. The thermocouple is housed in a stainless steel thermowell inserted into the vent gas pipe. The transmitter is mounted on top of the thermowell in an intrinsically safe housing. The thermocouple has a range of 0 to 200 ^{o}F and a rated accuracy of ± 0.1 percent of full scale. The 4 to 20mA output signal is wired directly into the GHG Center's DAS for data logging.

The thermocouple will be factory calibrated to NIST-traceable standards. Calibration certificates indicating conformance to these standards will be obtained from the factory, and reviewed to ensure the DQOs will be achieved. In addition, reasonableness checks will be performed by comparing the test instrument readings with those reported by a portable hand-held unit prior to insertion in the pipeline.

2.2.3.5 Ambient Temperature

Atmospheric temperature data will be monitored to identify site conditions at which verification testing will be performed. It will also help users of the technology determine applicability to their facilities. The temperature data may also be used to identify potential trends in gas recovery rates.

A Vaisala, Inc. Model HMD 60YO integrated temperature/humidity probe will be used. This unit is housed in a precipitation/radiation shield and designed for demanding outside environments. This unit uses a platinum 100 Ohm, 1/3 DIN RTD for temperature measurement. As the temperature changes, the resistance of the RTD changes. This change in resistance is detected and converted by associated electronic circuitry that provides a linear DC (4 to 20mA) output signal. The output signal is wired directly into the DAS for data logging. This sensor features electronic compensation to maintain accuracy over a broad range of temperature conditions.

The range and accuracy of the sensor is presented in Section 3.0. Rated linearity for the temperature sensor is 0.18^{o}F or better. The probe will be factory calibrated to NIST-traceable standards. Calibration certificates indicating conformance to these standards will be obtained from the laboratory. In addition, reasonableness checks will be performed by comparing the test instrument readings with those reported by a portable hand-held unit.

2.3 DETERMINATION OF ANNUAL GAS SAVINGS

The 1-minute gas recovery rates will be integrated over the verification period to determine the total volume of gas recovered by the EVRU. It will be computed as shown in Equation 8.

$$\text{Total Gas Recovered (scf)} = \int_{i = \text{min } 1}^{i = \text{end of verification test}} Q_{\text{recovered}, i} \qquad \text{(Eqn. 8)}$$

Where:

$Q_{\text{recovered},I}$ = Gas recovery rate for minute i, scfm (see Eqn. 1)

Because the duration of testing will be no more than 28 days, an estimate of annual gas savings (scfy) will require extrapolation of the total recovered gas. The site operator will be consulted to determine if the oil production rate, composition, process operating conditions, and other relevant conditions that existed during the field test are likely to persist for a year. If so, the total annual gas savings will be determined by multiplying the overall average recovery rate by the total number of operating days remaining in the year. The following equation will be used:

$$\underset{\text{(scfy)}}{\text{Est. Annual Gas Savings}} = \underset{\text{(scf)}}{(\text{Total Gas Recovered})} + \underset{\text{(scfd)}}{(Q_{\text{recovered, overall avg}})}\underset{\text{(days)}}{(\text{No. Days Remaining In Year})} \qquad \text{(Eqn. 9)}$$

Where:

$Q_{\text{recovered, overall avg}}$ = Overall average daily gas recovery rate (see Eqn. 3)

If the site operators expect oil production rates to vary significantly, a procedure different from that above will be used. It will be assumed that the vent gas volumes are proportional to the oil production rate. With the exception of production rate, all other operating conditions will be assumed to remain unchanged, and the vent gas volume or flash gas volume will be assumed to be directly proportional to crude oil throughput. To extrapolate annual gas savings, the GHG Center will first develop a gas recovery factor (total gas recovered divided by the total oil production) using measurements and process data collected as described earlier. This factor will be multiplied by projected gas production rates to estimate annual gas savings as shown in Equation 10.

$$\underset{\text{(scfy)}}{\textit{Est. Annual Gas Savings}} = \underset{\text{(scf)}}{\textit{Total Gas Recovered}} + \underset{\text{(scf/barrels)}}{\textit{(Gas Recovery Factor)}}\ \underset{\text{(barrels)}}{\textit{(Projected Oil Prod.)}} \qquad \text{(Eqn. 10)}$$

Where:

Gas Recovery Factor = Total gas recovered / Total oil production over the verification period
Projected Oil Prod. = Total oil production expected after the verification period for 1 year

2.4 DETERMINATION OF VALUE OF GAS RECOVERED

Total annual cash value of the recovered gas will be estimated by multiplying the estimated annual gas savings (scfy) with industry-accepted price for natural gas (Equation 11). The natural gas price will be obtained from the host site, and will be based on the measured heating value of the discharge gas stream.

$$\underset{\text{(\$/yr)}}{\textit{Annual Gas Savings}} = \underset{\text{(scfy)}}{\textit{[Est. Annual Gas Savings]}}\ \underset{(\$/\text{ft}^3)}{\textit{[Natural Gas Sales Price]}} \qquad \text{(Eqn. 11)}$$

2.5 DETERMINATION OF TOTAL INSTALLED COST

Capital cost and installation costs of the EVRU will be verified for the configuration installed at the test site. Capital cost will be verified by obtaining cost data from COMM and TFE and will include EVRU components (i.e., eductors, flow controllers, process monitors) and other equipment used during installation.

Installation costs will be verified by documenting the total labor hours expended for installing the EVRU, gas piping, high-pressure testing, and other activities related to configuration at the test site. Logs of labor requirements and invoices will be obtained from TFE contractors. The labor hours will be multiplied by the hourly rates charged by the contractors to calculate total installation cost. The sum of the capital equipment cost and installation cost will represent total EVRU installed cost. It will not include the costs for flow monitors and other devices required by the GHG Center for the verification test. A cost summary table will be preapred, similar to the example shown in Table 2-6.

Table 2-6. Example Illustrating Documentation of EVRU Installed Cost

Capital Equipment Costs ($)	**Source of Data**
EVRU Standard Equipment – eductor(s), flow controllers, sensors, etc.	COMM and TFE
EVRU Optional Equipment – flow measurement system	COMM
Gas Piping	COMM and TFE Contractors
Miscellaneous – electrical wiring, power source, etc.	COMM and TFE Contractors
Installation Costs[a] ($)	
EVRU Assembly Installation – includes time required to install the eductors, flow controllers, and other process instrumentation	TFE Contractors
Piping Installation – includes time required to install all gas piping, valves, headers, and sensors, system checks for leaks, and start-up/shake down activities)	TFE Contractors

[a] Actual labor rate(s) charged by the contractor will be used

3.0 DATA QUALITY

3.1 BACKGROUND

Verifications conducted by the GHG Center employ methodologies and instruments, which are selected to ensure that a stated level of data quality occurs in the final results. Data quality objectives (DQOs) specify the stated level of quality selected for verification parameters and these DQOs are specified before testing commences.

Each test measurement that contributes to the determination of a verification parameter has stated data quality indicators (DQIs) which, if met, ensure achievement of that parameter’s DQO. The process of establishing data quality objectives begins with determining the desired level of confidence in the verification parameters. The next step is to identify all measured values which affect the verification parameter, and determine the levels of error which can be tolerated. The DQI goals, most often stated in terms of measurement accuracy, precision, and completeness, are used to determine if the stated DQOs are satisfied.

The following section describes the measurements which contribute to the determination of the gas recovery rate verification parameter, how measurement uncertainty affects the determination, and the resulting DQO.

3.2 GAS RECOVERY RATE DATA QUALITY OBJECTIVES

Gas recovery rate is defined as the difference between the discharge gas and motive gas compensated flow rates. The following sources of uncertainty (or measurement error) contribute to the overall error, or DQO, for this verification parameter:

- Individual instrument errors for the motive gas and discharge gas flow meters
- Uncorrected variability in discharge gas composition

The following subsections discuss instrument errors, gas composition errors, and how they compound to contribute gas recovery rate errors. This section concludes with the gas recovery rate DQO specification and its reconciliation.

3.2.1 Flow Instrument Error

The test operator will program orifice size and material, meter run (pipe) size and material, and gas composition into each flow meter at the start of testing. The motive and discharge gas flow meters compute compensated flow in response to changing differential pressure (delta P) across a calibrated orifice, gas temperature, and pressure. The flow meters’ manufacturer states that, for gas compositions within the ranges specified in AGA Report No. 8 (AGA 1994), meter accuracy is ± 1.0 and ± 1.5 percent for the motive gas and discharge gas flow meters respectively. This is defined as the DQI goal for the flow meters.

Section 3.5.1 discusses the DQI goals for flow instruments. If these goals are achieved, the error will be assigned per manufacturer's specifications (1 percent or 1.5 percent). Section 3.2.3 describes the procedures for reconciling the DQO based on the actual error achieved.

3.2.2 Error Due to Changing Gas Composition

As stated in Section 2.2.1, gas composition must be programmed into each flow meter before testing commences. The motive gas will originate from the site's sales gas pipeline; this stream's composition is expected to be reasonably constant. Therefore, gas composition error for the motive gas flow rate is expected to be negligible.

Variations in discharge gas compositions are expected during testing due to changes in stock tank inventories, crude oil throughput, and other operating conditions. This introduces a potential problem because compensated flow is a function of discharge gas composition, and the flow meter does not allow real-time composition correction. The GHG Center does not plan to correct the discharge gas flow rates, but will report the errors associated with composition changes.

The effects of changing composition will be dampened due to the dilution ratio between motive gas and vent gas. Appendix C-1 illustrates an example calculation in which a reasonable variability in vent gas composition is assumed, and how such variability would impact the discharge gas composition. It also discusses how compositional changes away from a baseline composition programmed into the discharge flow meter would cause errors in the flows rates reported in the DAS. Tables C-1 and C-2 show that the maximum error due to the assumed compositional changes is 6.0 percent. This means that if discharge gas flow rates are left uncorrected, the relative difference between the actual flow rate and the reported flow rate will be ± 6.0 percent. This value is defined as the data quality indicator goal for discharge gas flow rates.

The GHG Center will collect and analyze gas samples prior to and during the test campaign. If the composition of each sample is within the range specified in Table 3-1, then the maximum absolute error due to changes in gas composition will be reported as 6.0 percent. This error will be left uncorrected, and will be carried to the DQO calculation as described in the next section. If a sample composition falls outside the allowed range, the procedures outlined in Appendix C-2 will be followed to determine the actual error achieved.

Table 3-1. Discharge Gas Composition Range to Achieve ± 6.0 % Discharge Gas Flow Error

Compound	Discharge Gas Composition (Volume %)
Methane	74.18 - 78.73
Ethane	8.41 - 9.14
Propane	5.67 - 4.58
Butanes	5.04 - 3.95
Pentanes	3.71 - 1.98
Hexanes	1.50 - 0.96
Heptanes	1.27 - 0.45
Nitrogen	0.05 - 0.12
Carbon Dioxide	0.10 - 0.17

3.2.3 Effects of Combined Errors

Discharge gas flow rate error is a multiplicative function of instrument error and error due to gas composition changes. With two multiplied values, an estimate of the compounded error (90 percent confidence interval) is as shown Equation 12 (EPA 1999):

$$err_c = \sqrt{(err_1)^2 + (err_2)^2 + \left((err_1)^2 (err_2)^2\right)} \qquad \text{(Eqn. 12)}$$

Where:

err_c = Compounded error, absolute value
err_1 = Error in first multiplied value, absolute value
err_2 = Error in second multiplied value, absolute value

Compounded error for the discharge gas flow rate is, therefore:

$$Error\ \ in\ \ Discharge\ Gas\ \ Flow\ \ Rate = \sqrt{(0.060)^2 + (0.015)^2 + \left((0.060)^2 (0.015)^2\right)} = \pm\, 0.062$$

Gas recovery rate is the difference between discharge and motive gas flow rates. An estimate of the compounded error of two subtracted values is shown in Equation 13 (EPA 1999):

$$err_c = \frac{\sqrt{[(Value_1)(err_1)]^2 + [(Value_2)(err_2)]^2}}{(Value_1 - Value_2)} \qquad \text{(Eqn. 13)}$$

Compounded error for gas recovery rate is:

$$Error\ \ in\ Vent\ \ Gas\ \ Recovery\ \ Rate = \frac{\sqrt{[(590)(0.062)]^2 + [(406)(0.01)]^2}}{(590 - 406)} = \pm\, 0.20$$

Where:

590 = assumed discharge gas flow rate, scfm
406 = assumed motive gas flow rate, scfm

90 percent of all gas recovery rates will be within ± 20 percent of the reported value. This is the DQO for the gas recovery rate verification parameter.

3.2.4 Gas Recovery Rate DQO and Its Reconciliation

Table 3-2 specifies the gas recovery rate DQO. If the instrument errors are within the specified values, and the discharge gas composition remains within the specified range for each component (Table 3-2), the achieved gas recovery rate error will be equal to or better than the ± 20 percent value derived above. Reconciliation of this DQO will be unnecessary. If the discharge gas composition falls outside this range, the GHG Center will calculate actual error according to the procedures outlined in Appendix C-2. This error will be the reconciled DQO.

Table 3-2. Gas Recovery Rate Data Quality Objectives

Error as a Percent of Gas recovery rate	± 20 %
Test Duration	At least one week of testing having 90 % of daily average gas recovery rate values within 0.30 times the overall average gas recovery rate **OR** 28 days of testing

Table 3-2 includes a specification for the test duration as a second DQO for gas recovery rate. Section 2.2 discusses the procedures involved. The Field Team Leader will evaluate attainment of this DQO by analyzing the daily average gas recovery rates. This will allow him to decide when to conclude testing and if data quality issues are occurring that require action prior to the completion of testing. If a DQI is not met, and if re-analysis, re-testing, or reconciliation is not possible or convincing, then the Project Manager will report the best available data as gathered with the notation that the applicable DQO was not achieved.

3.3 ANNUAL GAS SAVINGS DQO

Annual gas savings estimate in units of cubic feet per year is based on measured gas recovery rates, actual oil production rates during testing, and projected annual oil production rates. The data quality of gas recovery rate will be, as stated in Table 3-1, ± 20 percent if gas compositions are within the ranges specified in Table 3-2. The oil production rates (actual and projected) will be obtained directly from site operators, and will be assumed to be accurate.

3.4 VALUE OF GAS RECOVERED DQO

The value of recovered gas in units of dollars ($), is the industry average cost of natural gas multiplied by the annual cubic feet of gas saved. The industry average natural gas price ($/1000 ft^3) will be obtained from current, published market data or the host site, and will be assumed to be accurate. Because the natural gas price selected will be a function of the heating value of the gas saved, the data quality of annual gas savings will depend on the data quality of lower heating value measurements. Consistent with industry standards for custody transfer applications, the DQI goal for LHV analysis is defined to be ± 0.2 percent. Using the methodology outlined in Section 3.2.3, this error will compound with the ± 20 percent gas recovery rate error to yield an overall ± 20 percent error. This is the DQO for annual gas savings.

3.5 DETERMINATION OF MEASUREMENT INSTRUMENT DQIS

3.5.1 Gas Flow Rates

The two Rosemount mass flow meters used to monitor gas flow in the motive and discharge lines were discussed in Section 2.2.1. A series of QA/QC checks, summarized in Table 3-4, will be conducted on the meters to assess and/or demonstrate accuracy and completeness.

The primary method of reconciling the accuracy goal will be factory calibration of the Model 3095 transmitters. A calibration certificate traceable to the National Institute for Standards and Technology (NIST) will be obtained and reviewed to ensure that the desired accuracy was satisfied. The required accuracy for the meter on the motive gas line will be ± 1.0 percent of reading and accuracy for the meter on the discharge gas line will be ± 1.5 percent of reading. The factory certified calibration data are reported to be valid for three years, provided manufacturer-specified installation and set up procedures are followed.

Compensated flow rate measurements require realtime process pressure and temperature inputs. The flow meter's internal sensors will provide absolute pressure values. External Rosemount resistance temperature devices (RTD) will supply temperature data. As shown in Figure 2-2, two separate Series 68 platinum temperature sensors with 4-wire signal transmitters to the flow transmitters, will be used. Each RTD will be factory calibrated. Calibration certificates traceable to NIST will be obtained and reviewed to ensure the accuracy requirement was satisfied.

To validate the performance of the meter in the field, two forms of QC checks will be performed: sensor diagnostic checks; and reasonableness checks. Sensor diagnostic checks consist of zero flow verification by isolating the meters from the flow, equalizing the pressure across the differential pressure sensors using a crossover valve on the orifice assemblies, and reading the pressure differential and flow rate. The sensor output must read zero flow during these checks. Transmitter analog output checks will also be conducted at the beginning and end of the test. In this loop test, a current of known amount will be checked against an ammeter to ensure that 4 mA and 20 mA signals are produced. The procedures for conducting sensor diagnostic checks and log forms are provided in Appendix B.

Table 3-3. Measurement Instrument Specifications and Data Quality Indicator Goals

Site Measurements							Data Quality Indicator Goals		
Measurement Variable		Operating Range Expected in Field	Instrument Type / Manufacturer	Instrument Range	Instrument Rated Accuracy	Frequency of Measurements	Accuracy[a]	Completeness	How Verified / Determined
Gas Flow	Motive Gas Flow Rate[b]	160 to 440 scfm	Mass Flow Meter / Rosemount 3095	200 to 500 scfrm	± 1.0 % reading	1-second readings averaged over a 1-minute period	± 1.0 % reading	90 percent of 1-minute average readings over test period	Factory calibration prior to testing
	Discharge Gas Flow Rate[b]	240 to 650 scfm		200 to 650 scfm	± 1.5 % reading		± 1.5 % reading		
	Vent Gas Temperature[c]	30 °F to 100 °F	Type K Thermocouple / Omega	0 to 200 °F	± 0.10 % reading		± 0.10 % reading		
	Vent Gas Pressure[c]	2.5 to 8.5 in. H_2O	Pressure Transmitter / Rosemount 3051	-100 to 100 in. H_2O	± 0.08 % reading		± 0.08 % reading		
Vent and Discharge Gas Composition	Component concentrations	refer to Table 3-6	Gas Chromatograph / HP 589011	0 to 100 % for each component	± 0.02 % accuracy for components	Before Testing: 2 samples per day for 3 continuous days During Testing: minimum 2 samples per week	Defined as analytical repeatability – refer to Table 3-6	Minimum 3 valid samples per week	Repeatability check - duplicate analyses on the same sample
	Lower Heating Value	1,000 to 1,500 Btu/scf	Calculated using composition analysis	not applicable	± 0.1 % repeatability for LHV		± 0.2 %		
Ambient Meteorological Conditions	Ambient Temperature[c]	30 to 100 °F	Vaisala Model HMD 60UO/YO transmitter	-40 to 140 °F	± 0.9 °F	once per min	± 0.9 °F	95 % of 1-minute average readings over test period	Factory calibration prior to testing

FS: full-scale

[a] Accuracy goal represents the maximum error expected at the operating range. It is defined as the sum of instrument and sampling errors.

[b] Includes Rosemount supplied temperature sensors.

[c] These variables are not directly used to assess data quality objectives, but are used to determine if data quality indicator goals for key measurements are met. They are also used to form conclusions about the EVRU system performance.

Table 3-4. Summary of QA/QC Checks

Measurement Variable	QA/QC Check	When Performed/Frequency	Expected or Allowable Result	Response to Check Failure or Out of Control Condition
Motive and Discharge Gas Flow Rate	Instrument Calibration by Manufacturer*	Beginning of test	± 1.0 % reading on motive gas and ± 1.5 % reading on discharge gas	Identify cause of any problem and correct, or replace meter
	Sensor Diagnostics	Beginning and end of test	Pass	Identify cause of any problem and correct, or replace meter
	Reasonableness checks	Throughout test	Motive gas flow should be approximately 2/3 the value of discharge gas flow	Perform sensor diagnostic checks
Gas Composition and Heating Value	Duplicate analyses performed by laboratory*	At least twice during test period and on one blind audit sample	refer to Table 3-5	Repeat analysis
	Confirm canister is fully evacuated	Before collection of every sample	canister pressure < 1 psia	Reject canister
	Calibration with gas standards by laboratory	Prior to analysis of each lot of samples submitted	± 1.0 % for each gas constituent (C1 – C12)	Repeat analysis
	Independent performance check with blind audit sample	Two times during test period	± 3.0 % for each target gas constituent listed in Section 3.5.2	Apply correction factor to sample results
Ambient Meteorological Conditions	Instrument calibration by manufacturer or laboratory*	Beginning of test	Temp: ± 0.9 ^{o}F	Identify cause of any problem and correct, or replace meter
	Reasonableness checks	At least once during test period	Recording should be comparable with portable humidity and temperature sensor	Identify cause of any problem and correct, or replace meter
Vent Gas Pressure	Instrument calibration by manufacturer*	Beginning and end of test	± 0.075 % FS	Identify cause of any problem and correct, or replace meter
	Reasonableness checks	Throughout test	Readings should be less than 0.1 to 0.3 psig on vent gas and approx. 25 psig on discharge gas	Identify cause of any problem and correct, or replace meter

* Results of these QA/QC checks are used to reconcile data quality indicators

The transmitter electronics are programmed in the field to enable the meter to calculate gas flow rate at standard conditions (60 ^{o}F and 14.7 psia). The primary measurements used to compute the gas flow rate in scfm include orifice diameter, differential pressure across the orifice, gas temperature, gas pressure, and gas properties. Rosemount's Engineering Assistant (EA) Software, which is interfaced to the transmitter via a HART protocol serial modem, will be used to input information about expected gas properties and operating conditions. The GHG Center's planned approach for programming gas composition into the transmitters was presented in Section 2.2.1. Specific setup parameters required in the EA and installation/setup checks and log forms for this meter are provided in Appendix B-1. The GHG Center testing personnel will maintain field logs of all data entered into the EA, and subsequently transmitted to the instrument. An electronic copy of the EA configuration file will be maintained.

3.5.2 Gas Composition and Heating Value

QA/QC procedures for assessing data quality of gas composition determinations include duplicate analyses on at least two samples, review of laboratory instrument calibrations, analysis of a blind audit gas sample, and confirmation of canister pressure prior to sampling. The primary method of reconciling the DQI goal for gas composition will be the duplicate analysis results. The other three procedures will be conducted as additional QA/QC checks.

ASTM Specification D1945 provides repeatability guidelines that vary according to the component's concentration as illustrated in Table 3-5. Repeatability is defined as the difference between two successive results obtained by the same operator with the same apparatus under constant operating conditions.

Table 3-5. ASTM D1945 Repeatability Specifications

Component Concentration (mol %)	Repeatability (absolute difference between 2 results)
0 to 0.1	± 0.01
0.1 to 1.0	± 0.04
1.0 to 5.0	± 0.07
5.0 to 10	± 0.08
over 10	± 0.1

Using these guidelines, and the anticipated ranges of gas component concentrations, the target repeatability goals of primary gas components (i.e., components present in concentrations greater than 1 percent) are summarized in Table 3-6. For the purpose of evaluating analytical accuracy, the DQIs will be evaluated only on the primary gas components.

Table 3-6. DQIs for Anticipated Component Concentrations

Gas Component	Expected Concentration Range (mol %)		Repeatability DQI Goal (absolute difference of 2 results)	
	Vent Gas	Discharge Gas	Vent Gas	Discharge Gas
Methane	50 – 60	80 – 85	± 0.1	± 0.1
Ethane	10 – 15	5.0 – 5.5	± 0.1	± 0.08
Propane	8.0 - 10	3.0 – 4.0	± 0.08	± 0.07
Butane	8.0 – 12	3.0 – 4.5	± 0.1	± 0.07
Pentane	5.0 – 10	1.0 – 3.0	± 0.08	± 0.07
Hexane	1.0 – 3.0	0.5 – 1.0	± 0.07	na
Heptane	2.0 – 4.0	0.5 – 1.0	± 0.07	na

The additional QA/QC checks include instrument calibrations, analysis of a blind audit sample, and confirmation of canister pressures. The GC calibration procedures conducted at the laboratory were described in Section 2.2.2. Core Laboratories conducts the calibrations on a weekly basis or whenever equipment changes are made on the instrument using a Natural Gas GPA Reference Standard such as the example in Appendix B-3. ASTM Specification D1945 criteria for calibration states that consecutive analytical runs on the gas standard must be accurate to within ± 1 percent of the certified concentration of each component. The laboratory will be required to submit calibration results for each day samples are analyzed.

During field testing, the GHG Center will supply one blind/audit gas sample to the laboratory for analysis. The audit gas will be an independent Natural Gas GPA Reference Standard manufactured by Scott Specialty Gases with a certified analytical accuracy of ± 2 percent. The audit gas will be shipped to the test location and the sample will be collected in a canister immediately after one of the discharge gas samples is collected. The audit sample will then be shipped to the laboratory along with the vent and discharge gas samples, and analyzed in duplicate. The average result from the two analyses will be compared to the certified concentration of each constituent to determine if the results are within ± 3 percent (allowable error is the sum of the instrument calibration criteria and the analytical accuracy of the audit gas).

Finally, sample canister pressures will be checked before collection of each sample to confirm that the canisters were properly evacuated at the laboratory prior to shipment to the site and haven't leaked. A vacuum gauge will be used to measure the absolute pressure in each canister. These values will be recorded on log forms (Appendix A-3). Any canisters with absolute pressures greater than 1 psi will not be used for sampling.

Following ASTM Specification D3588 guidelines, gas LHV and density are calculated based on the gas compositional analysis. The validity of these parameters will therefore be evaluated based on the compositional analyses. The specification provides the equations that are used to calculate repeatability of the LHV calculations provided the analytical repeatability criteria (Table 3-6) are met. The repeatability expected for duplicate samples is approximately 1.2 Btu/1000 ft^3, or about 0.1 percent. Using input from the oil and gas industry and past experience with these analyses, a conservative DQI goal of ± 0.2 percent is established. If it is determined that the DQI goal for compositional analyses are met, then it can be deduced that the DQI goal for LHV has been met.

3.5.3 Ambient Conditions

Field procedures are detailed in the documentation provided for the integrated temperature/ humidity unit by Vaisala and will not be discussed here. In addition to the factory calibrations indicated in Tables 3-3 and 3-4, GHG Center testing personnel will follow all required procedures to ensure that checks for appropriate installation locations, length of cable, process connections, leaks, field wiring and ground wiring are conducted properly, including:

- All wires will not be located near motors, power supply cables, or other such electrically "noisy" equipment
- No hand-held radios will be used near the instruments

Reasonableness checks will be performed by examining the ambient temperature recorded by the test instruments with those reported by a portable hand-held unit (Thermo-Hygrometer PTH-1XA or equivalent). This instrument has rated accuracies of ± 2 ^{o}F for temperature. Readings between the two instruments should therefore be within ± 3 ^{o}F. All suspect data will be flagged, and the measurement instruments will be examined for damage or failure.

3.6 INSTRUMENT TESTING, INSPECTION, AND MAINTENANCE REQUIREMENTS

The equipment used to collect verification data will be subject to the pre- and post-test QC checks discussed earlier. Before the equipment leaves the GHG Center or analytical laboratories, it will be assembled exactly as anticipated to be used in the field and fully tested for functionality. For example, all controllers, flow meters, computers, instruments, and other sub-components of the measurements system (Figure 2-2) will be operated and calibrated as required by the manufacturer and/or this Test Plan. Any faulty sub-components will be repaired or replaced before being transported to the test site. A small amount of consumables and frequently needed spare parts will be maintained at the test site. Major sub-component failures will be handled on a case-by-case basis (e.g., by renting replacement equipment or buying replacement parts).

The instruments used to make gas flow rate measurements are new, having been purchased for this verification. They will be inspected at the GHG Center's laboratory prior to installation in the field to ensure all parts are in good condition. The equipment used to make gas pressure and temperature, and ambient measurements are maintained by the GHG Center's Environmental Studies Group. The mass flow meters, temperature, gas pressure, and other sensors will be submitted to the manufacturer for calibration prior to being transported to the test site.

3.7 INSPECTION/ACCEPTANCE OF SUPPLIES AND CONSUMABLES

Natural Gas Reference Standard gases will be used to calibrate the hydrocarbon analyzer, and to audit Core Laboratory gas analysis instrumentation that will be used to determine vent and discharge gas composition. The concentrations of components in the audit gas are certified within ± 2 percent of the tag value. Copies of the audit gas certifications will be available on-site during testing and archived at the GHG Center.

4.0 DATA ACQUISITION, VALIDATION, AND REPORTING

4.1 DATA ACQUISITION AND STORAGE

Test personnel will acquire the following types of data during the verification:

- Continuous process measurements (e.g., gas flow, gas pressure, gas temperature) and ambient temperature, to be collected by the GHG Center's DAS
- Motive gas compositional data supplied by the test facility
- Vent gas and discharge gas compositional data from canister samples collected by the Field Team Leader and submitted to Core Laboratories for analysis
- Site operating conditions to be supplied by the test facility

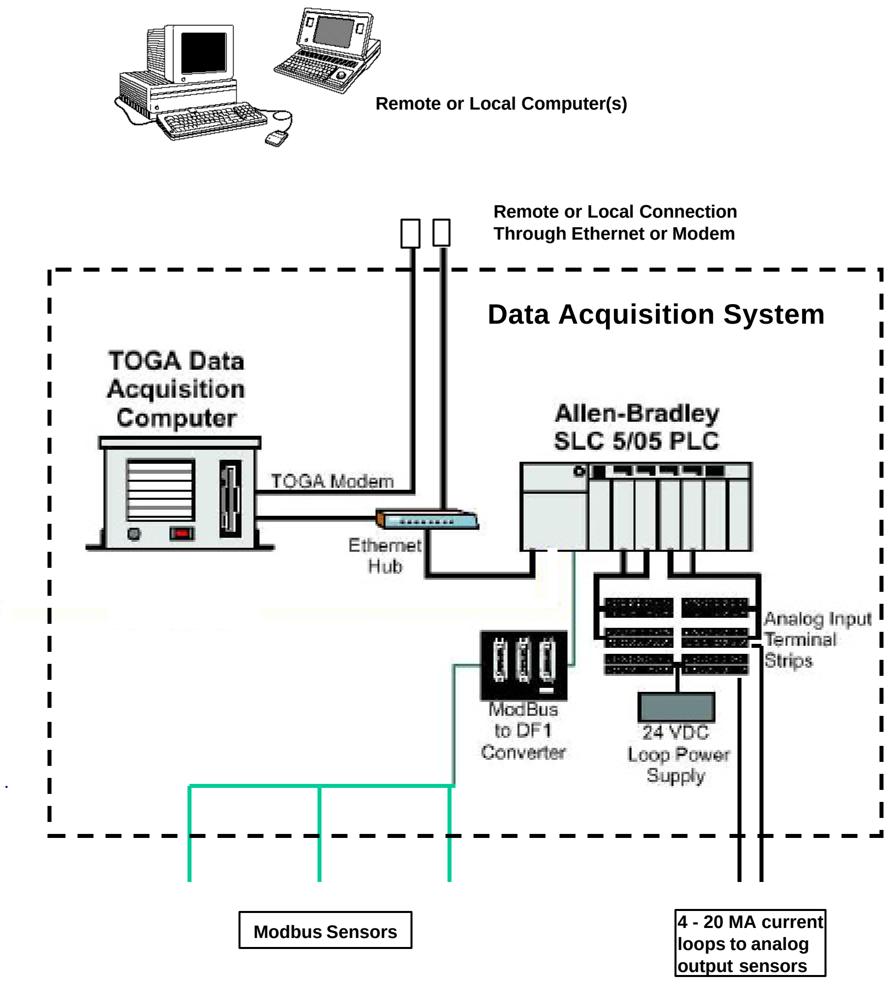
The Field Team Leader will also take site photographs and maintain a Daily Test Log which includes the dates and times of setup, testing, teardown, and other activities.

The Field Team Leader will submit digital data files, gas analyses, chain of custody forms, and the Daily Test Log to the Project Manager. The Project Manager will initiate the data review, validation, and calculation process. These submittals will form the basis of the Verification Report which will present data analyses and results in table, chart, or text format as is suited to the data type. The Verification Report's conclusions will be based on the data and the resulting calculations. The GHG Center will archive and store all data in accordance with the GHG Center QMP.

4.1.1 Continuous Measurements Data Acquisition

An electronic data acquisition system (DAS) will collect and store continuous process and ambient meteorological data. Core components of the DAS are an Allen-Bradley (AB) Model SLC 5/05 programmable logic controller (PLC) and a TOGA Gladiator Unix-based data acquisition computer (data server). Figure 4-1 is a schematic of the DAS.

Figure 4-1. DAS Schematic



The PLC brings all analog and digital signals from the measurement sensors together into a single realtime data source. The DAS can accommodate any combination of up to 16 analog signal channels with 4 to 20 mA current or DC voltage inputs. Sensors can also provide digital signals *via* the ModBus network to the DF1 interface unit. This converts the ModBus data to the AB DF1 protocol which is compatible with the PLC. The PLC nominally polls each sensor once per second and converts the signals to engineering units. It then computes 1-minute averages for export to the data server and applies a common time stamp to facilitate data synchronization of all measurements.

The data server records information from the PLC and contains the software for programming the PLC (e.g., data sampling rates, engineering unit conversions, calibration constants). Its UNIX operating system writes all PLC data to a My-SQL relational database for export to spreadsheet, graphics, and other programs. This database is ODBC-compliant, which means that almost any MS Windows^{TM} program can easily use the data. The data server includes an internal modem and Ethernet card for remote and local communications. During normal operations, the user accesses the data server with a portable laptop or remote computer (PC) *via* its communications port, Ethernet link, or telephone connection. Spreadsheets allow the user to download the entire database or only that portion which has been added since the last download. The user then conducts data queries (i.e. for certain times, dates, and selected data columns) on the downloaded data as needed.

During the verification test, GHG Center personnel will configure the DAS to acquire the process variables listed in the following table.

Table 4.1. DAS Channel Configuration

Channel	Measurement[a]
1	Ambient Temperature
2	Vent Gas Pressure
3	Vent Gas Temperature
4	Discharge Gas Flow Rate
5	Discharge Gas Pressure
6	Discharge Gas Differential Pressure
7	Discharge Gas Temperature
8	Motive Gas Flow Rate

[a] Refer to Table 3-2 for instrument ranges, expected values, and units

The GHG Center Field Team Leader will download test data either to a laptop computer or to a remote computer *via* modem at least once per day. Downloaded data will be copied to floppy disk or CD-ROM disk as soon as practicable after download. The GHG Center will archive the original data files and analysts will employ copies for data manipulations, queries, and presentations.

4.1.2 Gas Analysis Data

The sales gas stream from the dehydrator contact tower will provide the EVRU motive gas. The facility normally analyzes this gas stream once per month. The Field Team Leader will obtain copies of the motive gas analyses which occurred immediately prior to and immediately following the test campaign.

For the vent and discharge gas streams, the Field Team Leader will obtain canister samples (as described in Section 2.2.1) and forward them to Core Laboratories of Houston, TX, along with chain of custody forms. The laboratory will submit formal results for each sample, calibration records, duplicate analyses, reference materials analyses, etc. to the Field Team Leader within two weeks of the completion of testing.

Original data records will be archived according to GHG Center QMP requirements. Copies of data records will be used to conduct data manipulations, queries, and final reporting.

4.2 DATA REVIEW, VALIDATION, AND VERIFICATION

Data review and validation will primarily occur at the following stages:

- On-site -- by the Field Team Leader
- Before writing the draft Verification Report -- by the Project Manager
- During QA review of the draft Verification Report and audit of the data -- by the GHG Center QA Manager

Figure 1-5 identifies the individuals who are responsible for data validation and verification.

The Field Team Leader will be able to review, verify, and validate some data, such as DAS file data, reasonableness checks, etc., while on-site. Other data, such as discharge gas analysis results, must be reviewed, verified, and validated after testing has ended. The Project Manager holds overall responsibility for these tasks.

Upon review, all collected data will be classed as valid, suspect, or invalid. The GHG Center will employ the QA/QC criteria discussed in Sections 2.2 and 3.0; and specified in Tables 3-3 and 3-4. Review criteria are in the form of factory and on-site calibrations, maximum calibration and other errors, and audit gas analyses results, and lab repeatability results.

In general, valid results are based on measurements which meet the specified DQIs and QC checks, that were collected when an instrument was verified as being properly calibrated, and that are consistent with reasonable expectations (e.g., manufacturers' specifications, professional judgement).

The data review process often identifies anomalous data. Test personnel will investigate as much of the outlying or unusual values in the field as possible. Anomalous data may be considered suspect if no specific operational cause to invalidate the data is found.

All data, valid, invalid, and suspect will be included in the Verification Report. However, report conclusions will be based on valid data only and the Verification Report will justify the reasons for excluding any data. Suspect data may be included in the analyses, but may be given special treatment as specifically indicated. If the DQI goals cannot be met due to excessive data variability, the Project Manager will decide to either continue the test, collect additional data, or terminate the test and report the data obtained.

The QA Manager reviews and validates the data and Verification Report using the Test Plan and test method procedures. The data review and data audit will be conducted in accordance with the GHG Center's QMP. For example, the QA Manager will randomly select raw data and independently calculate the Performance Verification Parameters dependent on that data. The comparison of these calculations with the results presented in the Verification Report will yield an assessment of the QA/QC procedures employed by the GHG Center.

4.3 RECONCILIATION OF DATA QUALITY OBJECTIVES

A fundamental component of all verifications is the reconciliation of the data and its quality as collected from the field with the data quality objectives (DQOs).

In general, the Field Team Leader and Project Manager will review the collected data to ensure they are valid and consistent with expectations. They will assess the quality of the data in terms of accuracy and completeness as they relate to the stated DQI goals (Table 3-3). If the test data show that DQI goals were met, then it will be concluded that DQOs were achieved. Section 3.2.4 discussed the reconciliation process of the gas recovery rate DQO, and is not repeated here. The GHG Center will assess the achievement of DQI goals during field testing because QC checks and calibrations will be performed on site or prior to testing. Other DQIs, such as gas analysis repeatability, will be verified after the field tests have concluded.

4.4 ASSESSMENTS AND RESPONSE ACTIONS

The quality of the project and associated data are assessed within the project by the Field Team Leader, Project Manager, QA Manager, GHG Center Director, and technical peer-reviewers. Quality assessment and oversight for the project activities are performed through the review of data, audits, and reports by the Project Manager and independently by the QA Manager.

The effectiveness of implementing the Test Plan is assessed through project reviews, audits, and data quality assessment.

4.4.1 Project reviews

The review of project data and the writing of project reports are the responsibility of the Project Manager, who also is responsible for conducting the first complete assessment of the project. Although the project's data are reviewed by the project personnel and assessed to determine that the data meet the measurement quality objectives, it is the Project Manager who must assure that overall the project activities meet the measurement objectives and DQOs.

The second review of the project is performed by the GHG Center Director, who is responsible for ensuring that the project's activities adhere to the requirements of the program and expectations of the stakeholders. The GHG Center Director's review of the project will also include an assessment of the overall project operations to ensure that the Field Team Leader has the equipment, personnel, and resources to complete the project as required, and to deliver data of known and defensible quality.

The third review is that of the QA Manager, who is responsible for assuring that the program management systems are established and functioning as required by the QMP and corporate policy. The QA Manager is the final reviewer within the SRI organization, and is responsible for assuring that QA requirements have been met.

The draft document will be then reviewed by COMM. This will be followed by a review from the host site and selected members of the oil and natural industry (minimum of two industry experts). Technically competent persons who are familiar with the technical aspects of the project, but not involved with the conduct of project activities, will perform the peer-reviews. The peer-reviewers will provide written comments to the Project Manager on the technical aspects of the project. Further details on project review requirements can be found in the GHG Center's QMP.

The Verification Report will then be submitted to EPA QA personnel, and all comments will be addressed by the Project Manager. Following this review, the Verification Report will undergo various EPA management reviews, including the EPA-APPCD Project Officer, EPA ORD Laboratory Director, and EPA Technical Editor.

4.4.2 Inspections

Although not planned, inspections may be conducted by the Project Manager or the QA Manager. Inspections assess activities that are considered important or critical to key activities of the project. These critical activities may include, but are not limited to, pre- and post-test calibrations, sample equipment preparation, data collection, sample analysis, or data reduction. Inspections are assessed with respect to the Test Plan or other established methods, and are documented in the field records. The results of any inspections are reported to the Project Manager and QA Manager. Any deficiencies or problems found during the inspections must be investigated and the results and responses or corrective actions reported in a Corrective Action Report (CAR), shown in Appendix B-6.

4.4.3 Audit of Data Quality

The audit of data quality (ADQ) is an evaluation of the measurement, processing, and evaluation steps to determine if systematic errors have been introduced. During the ADQ, the QA Manager will randomly select approximately 10 percent of the data to be followed through the analysis and data processing. The scope of the ADQ is to verify that the data-handling system is correct and to assess the quality of the data generated.

The ADQ, as part of the system audit, is not an evaluation of the reliability of the data presentation. The review of the data presentation is the responsibility of the Project Manager and the technical peer-reviewer.

4.4.4 Technical Systems Audit

The Technical Systems Audit (TSA) will be conducted by the QA Manager during all phases of project activities. This audit will evaluate all components of the data gathering and management system to determine if these systems have been properly designed to meet the DQOs for this test. The TSA includes a review of the experimental design, the Test Plan, and planned field procedures prior to field activities. The review also includes an assessment of personnel qualifications, adequacy and safety of the facility and equipment, and the data management system.

During field testing activities, the QA Manager will inspect the analytical activities and determine their adherence to the Test Plan. The auditor reports any area of nonconformance to the Field Team Leader through an audit report. The audit report may contain corrective action recommendations. If so, follow-up inspections may be required and should be performed to ensure that corrective actions are taken.

4.5 DOCUMENTATION AND REPORTS

During the different activities on this project, documentation and reporting of information to management and project personnel are critical. To insure the complete transfer of information to all parties involved in this project, the following field test documentation, QC documentation, corrective action/assessment report, and Verification Report will be prepared.

4.5.1 Field Test Documentation

The Field Team Leader will record all important field activities. The Field Team Leader reviews all data sheets and maintains them in an organized file. The required test information was described earlier in Sections 2.0 and 3.0. The Field Team Leader will also maintain a field notebook that documents the activities of the field team each day and any deviations from the schedule, Test Plan, or any other significant event. Any major problems found during testing requiring corrective action will be reported immediately by the Field Team Leader to the Project Manager through a CAR. The Field Team Leader will document this in the project files and report it to the QA Manager.

The Project Manager will check the test results with the assistance of the Field Team Leader to determine whether the QA criteria were satisfied. Following this review and confirmation that the appropriate data were collected and DQOs were satisfied, the GHG Center Director will be notified.

At the end of the EVRU installation process and start-up/shakedown activities are completed, the Field Team Leader will obtain copies of invoices and labor hours from COMM and on-site contractors. A copy of the field test documentation will be submitted to the Project Manager. These copies, original data, reports, notes, and other documents will be stored in the project records, as required by the QMP.

4.5.2 QC Documentation

After the completion of verification test, test data, sampling logs, calibration records, certificates of calibration, and other relevant information will be stored in the project file in the GHG Center's RTP office. Calibration records will include information about the instrument being calibrated, raw calibration data, calibration equations, analyzer identifications, calibration dates, calibration standards used and their traceabilities, calibration equipment, and staff conducting the calibration. These records will be used to prepare the Data Quality section in the Verification Report, and made available to the QA Manager during audits.

4.5.3 Corrective Action and Assessment Reports

A corrective action is the process that occurs when the result of an audit or quality control measurement is shown to be unsatisfactory, as defined by the DQOs or by the measurement objectives for each task. The corrective action process involves the Field Team Leader, Project Manager, and QA Manager. A written Corrective Action Report, included in Appendix B-6, is required on major corrective actions that deviate from the Test Plan.

Since the tasks of this study involve a validation process to ensure data quality for the technology being verified, predetermined limits for the data acceptability have been established in the measurement and DQOs. Therefore, data determined to deviate from these objectives require evaluation through immediate corrective action.

The immediate corrective action process responds quickly to improper procedures, indications of malfunctioning equipment, or suspicious data. The Field Team Leader, as a result of calibration checks and internal quality control sample analyses, will most frequently identify the need for such an action. The Project Manager will be notified of the problem immediately, who will take and document appropriate action. The Project Manager is responsible for and is authorized to halt the work if it is determined that a serious problem exists. The Field Team Leader is responsible for implementing corrective actions identified by the Project Manager, and is authorized to implement any procedures to prevent the recurrence of problems.

The results of the ADQ conducted by the QA Manager will be routed to the Project Manager for review, comments, and corrective action. The results will be documented in the project records. The Project Manager will take any necessary corrective action needed and will respond by addressing the QA Manger's comments in the Verification Report.

4.5.4 Verification Report and Verification Statement

A Verification Report and Statement (Verification Report) will be prepared within 6 weeks of completing the field test, if possible, by the Project Manager. The Verification Report will specifically address the results of the verification parameters identified in the Test Plan.

The Project Manager will submit the Verification Report to the QA Manager and GHG Center Director for review. The Verification Report will contain a Verification Statement, which is a 3 to 4 page summary of the COMM EVRU technology, the test strategy used, and the verification results obtained. The Verification Report will summarize the results for each verification parameter discussed in Section 2.0 and will contain sufficient raw data to support findings and allow others to assess data trends, completeness, and quality. Clear statements will be provided which characterize the performance of the verification parameters identified in Sections 1.0 and 2.0. A preliminary outline of the Verification Report is shown below.

Preliminary Outline
COMM EVRU Verification Report

Verification Statement

Section 1. ETV Overview

Verification Factors
Technology Description
Section 2. Verification Test Design and Approach
Section 3. Verification Results and Evaluation
Section 4. Data Quality Assessment
Section 5. Additional Information Provided by COMM (optional)
References

4.6 TRAINING AND QUALIFICATIONS

The GHG Center's Field Team Leader has extensive experience (>15 years) in field testing of air emissions from many types of sources. He is familiar with natural gas flow measurements from production, processing and transmission stations, as well as the requirements of all of the test methods and standards that will be used in the verification test.

The Project Manager has performed numerous field verifications under the ETV program, and is familiar with requirements mandated by the EPA and GHG Center QMPs. The QA Manager is an independently appointed individual whose responsibility is to ensure the GHG Center's activities are performed according to the EPA approved QMP.

4.7 HEALTH AND SAFETY REQUIREMENTS

This section applies to GHG Center personnel only. Other organizations involved in the project have their own health and safety plans that are specific to their roles in the project.

GHG Center staff will comply with all known host, state/local and Federal regulations relating to safety at the test facility. This includes use of personal protective gear (e.g., safety glasses, hard hats, hearing protection, safety toe shoes) as required by the host and completion of site safety orientation (i.e., site hazard awareness, alarms and signals).

5.0 REFERENCES

AGA 1992. *Orifice Metering of Natural Gas Part 3: Natural Gas Applications.* AGA Report No. 3, AGA Catalog #XQ9210-IN1, American Gas Association, Washington, DC. 1992.

AGA 1994. *Compressibility and Super Compressibility for Natural Gas and Other Hydrocarbon Gases (Revised)*. AGA Report No. 8, AGA Catalog #XQ9212-IN1, American Gas Association, Washington, DC. 1994.

API 1997. *Evaluation of a Petroleum Production Tank Emissions Model*. Publication #4662, American Petroleum Institute, Health and Environmental Sciences Department, Washington, DC. October 1997.

ASTM 2001a. *Standard Test method for Analysis of Natural Gas by Gas Chromatography*. ASTM-D1945-96ei, American Society for Testing and Materials, West Conshohocken, PA. 2001.

ASTM 2001b. *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*. ASTM-D3588-98, American Society for Testing and Materials, West Conshohocken, PA. 2001.

Boyer and Brodnax 1996. *Oil and Gas Production Emission Factors and Estimation Methods*. Complete Oil Field Management and Maintenance, Inc., Lafayette, LA and Mobil Exploration and Production Company, Houston, TX. Boyer, Brian E. and Kenneth Brodnax, Presented at the Emission Inventory: Key to Planning Permits, Compliance and Reporting Conference, Air and Waste Management Association, New Orleans, LA. September 4-6, 1996.

CFR Title 40 Part 63. *National Emission Standards for Hazardous Air Pollutants For Source Catagories.* Federal Register, U.S. Environmental Protection Agency Code of Federal Regulations (CFR), Washington, DC. June 17, 1999.

EPA 1995. *Compilation of Air Pollutant Emission Factors. Volume I: Stationary Point and Area Sources, Fifth Edition, AP-42, Section 7.1, Organic Liquid Storage Tanks.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC. 1995.

EPA 1999. *Methane Emissions From the U.S. Petroleum Industry*. EPA-600/R-99-010, Environmental Protection Agency, Office of Research and Development, Research Triangle Park, NC. February, 1999.

GPA 2000. *Tentative Method of Extended Analysis for Natural Gas and Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography*. GPA Standard 2286-95, Gas Processors Association, Tulsa, OK. 2000.

GRI 1994. *Preliminary Assessment of Air Toxic Emissions in the Natural Gas Industry, Phase I, Topical Report*. GRI-94/0268, Gas Research Institute, Chicago, IL. 1994.

GRI 1995. *Glycol Dehydrator Emissions: Sampling and Analytical Methods and Estimation Techniques, Volume I.* GRI-94/0324.1, Gas Research Institute, Chicago, IL. 1995.

ICF 1997. *Estimates of Methane Emissions From the U.S. Oil Industry (Draft)*. ICF Kaiser International, Inc., Fairfax, VA. November 1997.

APPENDIX A

Test Procedures and Field Log Forms

Appendix A-1. Daily Test Log

Date: ______________________________ Page: ________

Time (use 24-hr.)	**Notes**

SIGNATURE: ____

Appendix A-2. Gas Sampling Procedures
(Vent Gas and EVRU Discharge Gas)

1. Attach a leak free vacuum gauge to the inlet of a pre-evacuated stainless steel sample canister. Open the canister inlet valve and verify that the canister is fully evacuated. Record the absolute pressure.

2. Close the inlet valve and attach the canister to the sample port on the gas line being sampled.

3. Open the fuel line valve upstream of the canister, and open the inlet valve on the canister. Allow the canister to fill with gas until about 5 inches (Hg) of vacuum remains in the cylinder.

4. Close all valves and remove canister from the sampling port. Record date, time, canister ID number, final canister pressure, and gas temperature on sample log form (Appendix A-3).

5. Return collected samples to Core Laboratories along with completed chain-of-custody form (Appendix A-4).

   Core Laboratories' Analytical Procedures:

   (a) Samples are received with proper chain-of-custody form and logged into the laboratory system for analysis.
   (b) Samples are heated to the temperature recorded during sampling, injected into the GC, and analyzed. The GC determines gas constituent concentrations based on the areas of the chromatograph peaks relative to the gas standard.
   (c) Duplicate analysis is conducted on one sample per lot.
   (d) Gas density, HHV, and LHV are calculated using results of each analysis and equations provided in ASTM D3588.
   (e) Hard copies of calibration records and results will be submitted to the GHG Center.
   (f) Determine repeatability based on the duplicate analyses.

Appendix A-3. Gas Sampling Log

Project: ______________________

Location: ______________________

Source: ______________________

Sampler: ______________________

Ambient Pressure ______________

Ambient Temp. ______________

Sample ID	Date/Time	Gas Temp.(°F)	Canister ID	Initial Press. (psig)	Final Press. (psig)

Appendix A-4. Gas Sampling Chain of Custody Record

Project: ______________________
Location: ______________________
Source: ______________________
Sampler: ______________________

Sample Date(s): ______________________
Shipping Date: ______________________
Laboratory: ______________________
Lab Address: ______________________
____
____

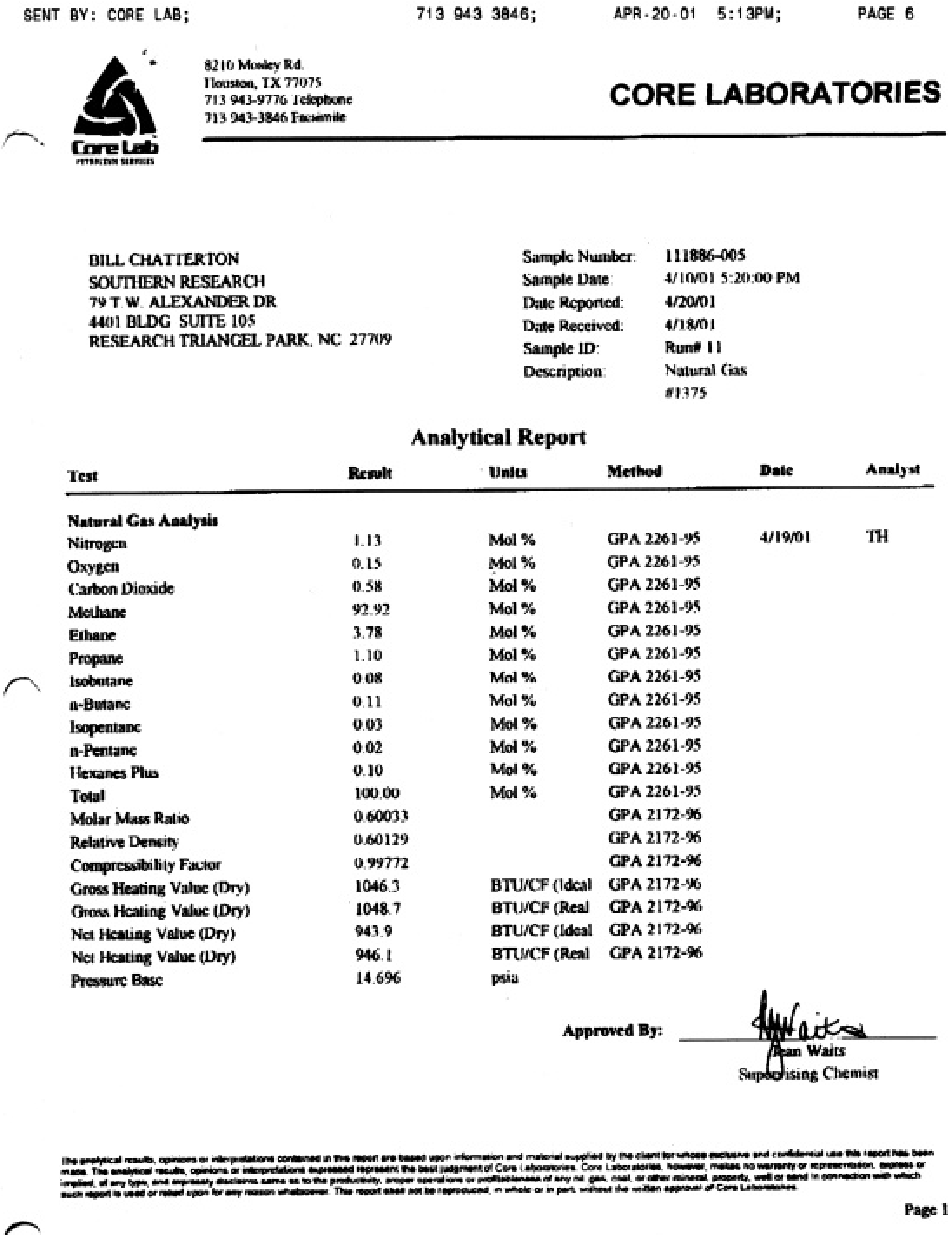
Sample ID	Date/Time	Gas Temp.(^{o}F)	Canister ID	Initial Press. (psig)	Final Press. (psig)	Laboratory Sample ID

Relinquished by: ______________________ Date/Time: ______________________
Received by: ______________________ Date/Time: ______________________

Relinquished by: ______________________ Date/Time: ______________________
Received by: ______________________ Date/Time: ______________________

Relinquished by: ______________________ Date/Time: ______________________
Received by: ______________________ Date/Time: ______________________

Appendix A-5. Example of Core Laboratories Gas Analysis Results



SENT BY: CORE LAB;   713 943 3846;   APR-20-01 5:13PM;   PAGE 6

Core Lab
PETROLEUM SERVICES

8210 Mosley Rd.
Houston, TX 77075
713 943-9776 Telephone
713 943-3846 Facsimile

CORE LABORATORIES

BILL CHATTERTON
SOUTHERN RESEARCH
79 T.W. ALEXANDER DR
4401 BLDG SUITE 105
RESEARCH TRIANGEL PARK, NC 27709

Sample Number: 111886-005
Sample Date: 4/10/01 5:20:00 PM
Date Reported: 4/20/01
Date Received: 4/18/01
Sample ID: Run# 11
Description: Natural Gas
#1375

Analytical Report

Test	Result	Units	Method	Date	Analyst
Natural Gas Analysis					
Nitrogen	1.13	Mol %	GPA 2261-95	4/19/01	TH
Oxygen	0.15	Mol %	GPA 2261-95		
Carbon Dioxide	0.58	Mol %	GPA 2261-95		
Methane	92.92	Mol %	GPA 2261-95		
Ethane	3.78	Mol %	GPA 2261-95		
Propane	1.10	Mol %	GPA 2261-95		
Isobutane	0.08	Mol %	GPA 2261-95		
n-Butane	0.11	Mol %	GPA 2261-95		
Isopentane	0.03	Mol %	GPA 2261-95		
n-Pentane	0.02	Mol %	GPA 2261-95		
Hexanes Plus	0.10	Mol %	GPA 2261-95		
Total	100.00	Mol %	GPA 2261-95		
Molar Mass Ratio	0.60033		GPA 2172-96		
Relative Density	0.60129		GPA 2172-96		
Compressibility Factor	0.99772		GPA 2172-96		
Gross Heating Value (Dry)	1046.3	BTU/CF (Ideal	GPA 2172-96		
Gross Heating Value (Dry)	1048.7	BTU/CF (Real	GPA 2172-96		
Net Heating Value (Dry)	943.9	BTU/CF (Ideal	GPA 2172-96		
Net Heating Value (Dry)	946.1	BTU/CF (Real	GPA 2172-96		
Pressure Base	14.696	psia			

Approved By: DWaits
Dean Waits
Supervising Chemist

Appendix A-6. Process Operating Conditions Log

Date	Oil Production Rate (bopd)	Separator Pressure (psi)	Separator Temperature (°F)

APPENDIX B

Quality Assurance/Quality Control Checks and Log Forms

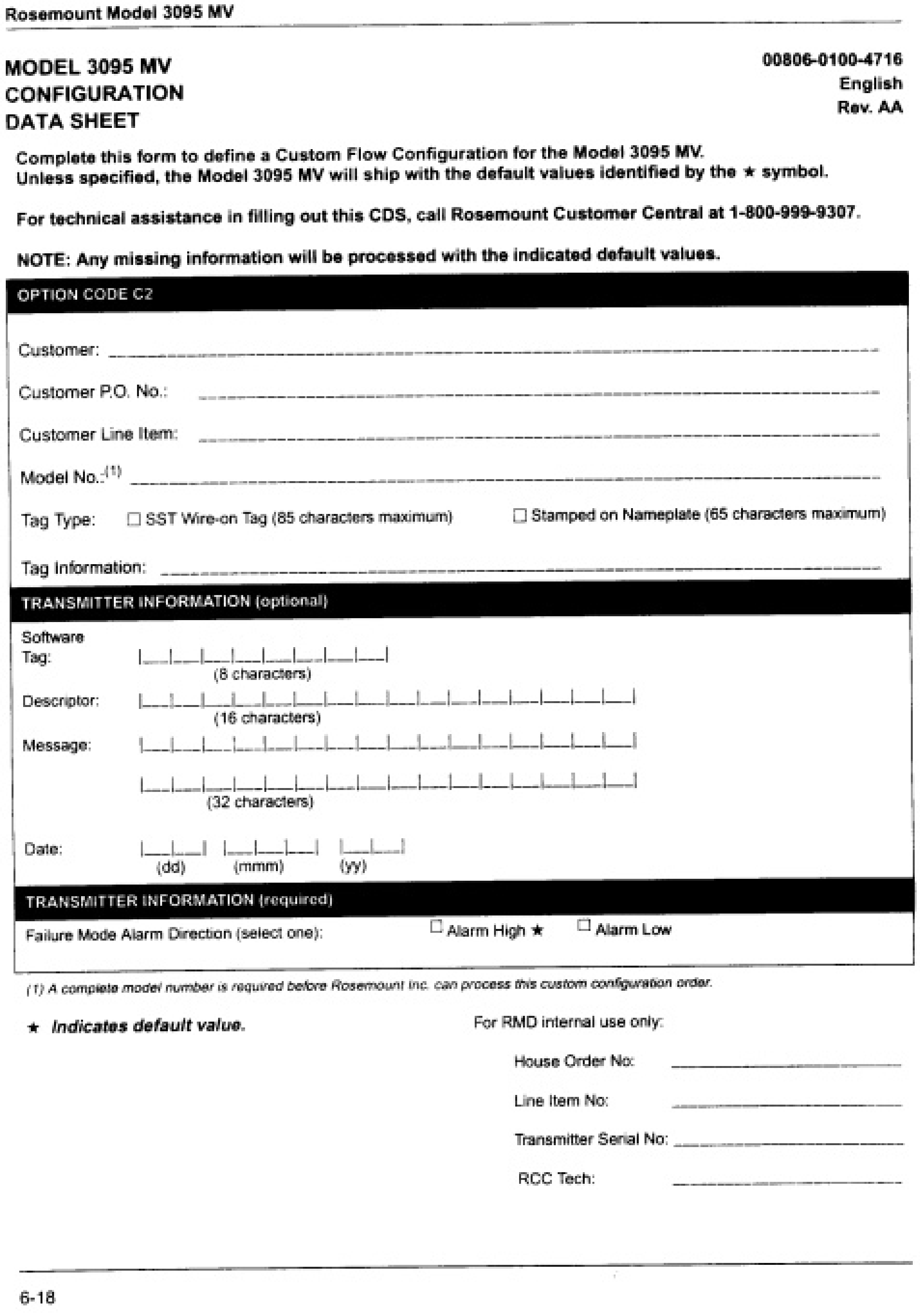
Appendix B-1. Rosemount 3095 Installation and Setup Checks/Log Form

Manufacturer's installation checks: Field installation procedures are well documented in Rosemount's "Model 3095 MV Product Manual", and will not be repeated here in entirety. GHG Center testing personnel will follow all required procedures to ensure that checks for process connections, leaks, field wiring, and ground wiring are conducted properly. The Product Manual will be made available during installation. Following manual specifications, meter installation will be conducted using the following considerations:

1. The meter will be installed vertically in the 1-inch diameter fuel line in a safe, accessible, and vibration free section of pipe.
2. Installation will include sufficient straight run of pipe (no less than 20 diameters) upstream and downstream of the meter.
3. Temperature sensors will be installed in the piping and wired to the transmitters for continuous temperature compensation.
4. All mechanical connections will be leak checked.
5. All electrical connections will be made following manufacturer specifications and tested.

Manufacturer's setup and start-up checks: In each flow sensor element, a transmitter calculates mass from differential pressure across an integral orifice element. To perform this calculation, the transmitter electronics must be programmed with information on the gas being metered and the operating conditions. This is accomplished using Rosemount's Engineering Assistant (EA) Software, which is interfaced to the transmitter via a HART protocol serial modem. Specific setup parameters required in the EA are listed in the following pages. The GHG Center testing personnel will maintain field logs of all data entered into the EA, and subsequently transmitted to the instrument. An electronic copy of the configuration file will be maintained. Detailed guidelines are provided in the Product Manual.

Appendix B-1. Rosemount 3095 Installation and Setup Checks/Log Form
(continued)



Rosemount Model 3095 MV

MODEL 3095 MV
CONFIGURATION
DATA SHEET

00806-0100-4716
English
Rev. AA

Complete this form to define a Custom Flow Configuration for the Model 3095 MV.
Unless specified, the Model 3095 MV will ship with the default values identified by the ★ symbol.

For technical assistance in filling out this CDS, call Rosemount Customer Central at 1-800-999-9307.

NOTE: Any missing information will be processed with the indicated default values.

OPTION CODE C2

Customer: ______________________________

Customer P.O. No.: ______________________________

Customer Line Item: ______________________________

Model No.:[1] ______________________________

Tag Type: ☐ SST Wire-on Tag (85 characters maximum) ☐ Stamped on Nameplate (65 characters maximum)

Tag Information: ______________________________

TRANSMITTER INFORMATION (optional)

Software Tag: |__|__|__|__|__|__|__|__| (8 characters)

Descriptor: |__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__| (16 characters)

Message: |__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|
|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__|__| (32 characters)

Date: |__|__| (dd) |__|__|__| (mmm) |__|__| (yy)

TRANSMITTER INFORMATION (required)

Failure Mode Alarm Direction (select one): ☐ Alarm High ★ ☐ Alarm Low

---

(1) A complete model number is required before Rosemount Inc. can process this custom configuration order.

★ ***Indicates default value.***

For RMD internal use only:

House Order No: ____________

Line Item No: ____________

Transmitter Serial No: ____________

RCC Tech: ____________

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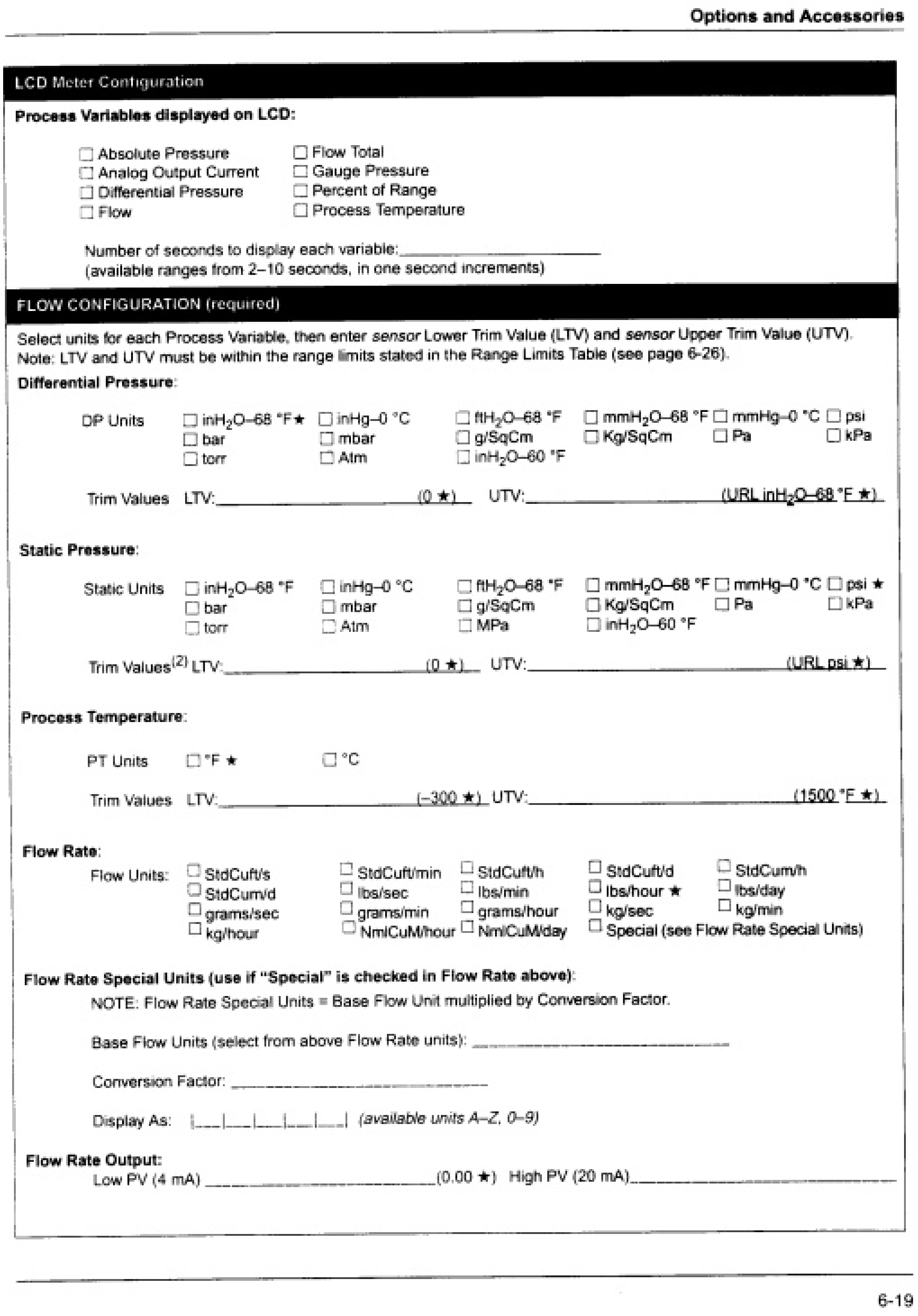
Appendix B-1. Rosemount 3095 Installation and Setup Checks/Log Form
(continued)



LCD Meter Configuration

Process Variables displayed on LCD:

☐ Absolute Pressure
☐ Analog Output Current
☐ Differential Pressure
☐ Flow
☐ Flow Total
☐ Gauge Pressure
☐ Percent of Range
☐ Process Temperature

Number of seconds to display each variable: ______________________
(available ranges from 2–10 seconds, in one second increments)

FLOW CONFIGURATION (required)

Select units for each Process Variable, then enter *sensor* Lower Trim Value (LTV) and *sensor* Upper Trim Value (UTV).
Note: LTV and UTV must be within the range limits stated in the Range Limits Table (see page 6-26).

Differential Pressure:

DP Units
☐ inH$_2$O–68 °F ★
☐ bar
☐ torr
☐ inHg–0 °C
☐ mbar
☐ Atm
☐ ftH$_2$O–68 °F
☐ g/SqCm
☐ inH$_2$O–60 °F
☐ mmH$_2$O–68 °F
☐ Kg/SqCm
☐ mmHg–0 °C
☐ Pa
☐ psi
☐ kPa

Trim Values LTV: ______________________ (0 ★) UTV: ______________________ (URL inH$_2$O–68 °F ★)

Static Pressure:

Static Units
☐ inH$_2$O–68 °F
☐ bar
☐ torr
☐ inHg–0 °C
☐ mbar
☐ Atm
☐ ftH$_2$O–68 °F
☐ g/SqCm
☐ MPa
☐ mmH$_2$O–68 °F
☐ Kg/SqCm
☐ inH$_2$O–60 °F
☐ mmHg–0 °C
☐ Pa
☐ psi ★
☐ kPa

Trim Values(2) LTV: ______________________ (0 ★) UTV: ______________________ (URL psi ★)

Process Temperature:

PT Units ☐ °F ★ ☐ °C

Trim Values LTV: ______________________ (–300 ★) UTV: ______________________ (1500 °F ★)

Flow Rate:

Flow Units:
☐ StdCuft/s
☐ StdCum/d
☐ grams/sec
☐ kg/hour
☐ StdCuft/min
☐ lbs/sec
☐ grams/min
☐ NmlCuM/hour
☐ StdCuft/h
☐ lbs/min
☐ grams/hour
☐ NmlCuM/day
☐ StdCuft/d
☐ lbs/hour ★
☐ kg/sec
☐ Special (see Flow Rate Special Units)
☐ StdCum/h
☐ lbs/day
☐ kg/min

Flow Rate Special Units (use if "Special" is checked in Flow Rate above):

NOTE: Flow Rate Special Units = Base Flow Unit multiplied by Conversion Factor.

Base Flow Units (select from above Flow Rate units): ______________________________

Conversion Factor: ______________________________

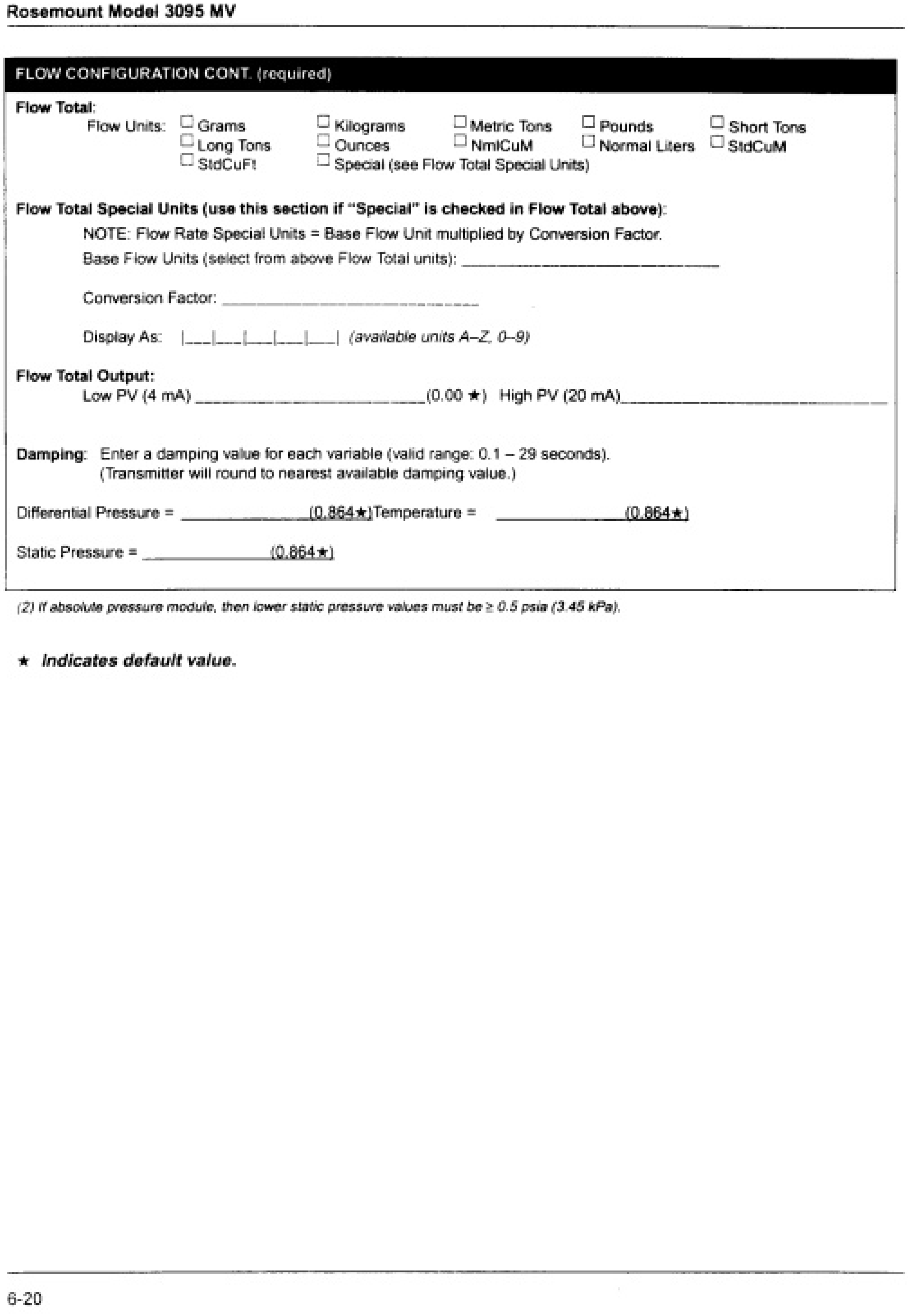
Display As: |___|___|___|___|___| *(available units A–Z, 0–9)*

Flow Rate Output:

Low PV (4 mA) ______________________ (0.00 ★) High PV (20 mA) ______________________

Appendix B-1. Rosemount 3095 Installation and Setup Checks/Log Form

(continued)



Rosemount Model 3095 MV

FLOW CONFIGURATION CONT. (required)

Flow Total:

Flow Units: ☐ Grams ☐ Kilograms ☐ Metric Tons ☐ Pounds ☐ Short Tons
☐ Long Tons ☐ Ounces ☐ NmlCuM ☐ Normal Liters ☐ StdCuM
☐ StdCuFt ☐ Special (see Flow Total Special Units)

Flow Total Special Units (use this section if "Special" is checked in Flow Total above):

NOTE: Flow Rate Special Units = Base Flow Unit multiplied by Conversion Factor.

Base Flow Units (select from above Flow Total units): ______________________________

Conversion Factor: ______________________________

Display As: |___|___|___|___|___| *(available units A–Z, 0–9)*

Flow Total Output:

Low PV (4 mA) ___________________________(0.00 ★) High PV (20 mA)______________________________

Damping: Enter a damping value for each variable (valid range: 0.1 – 29 seconds).
(Transmitter will round to nearest available damping value.)

Differential Pressure = _______________(0.864★)Temperature = _______________(0.864★)

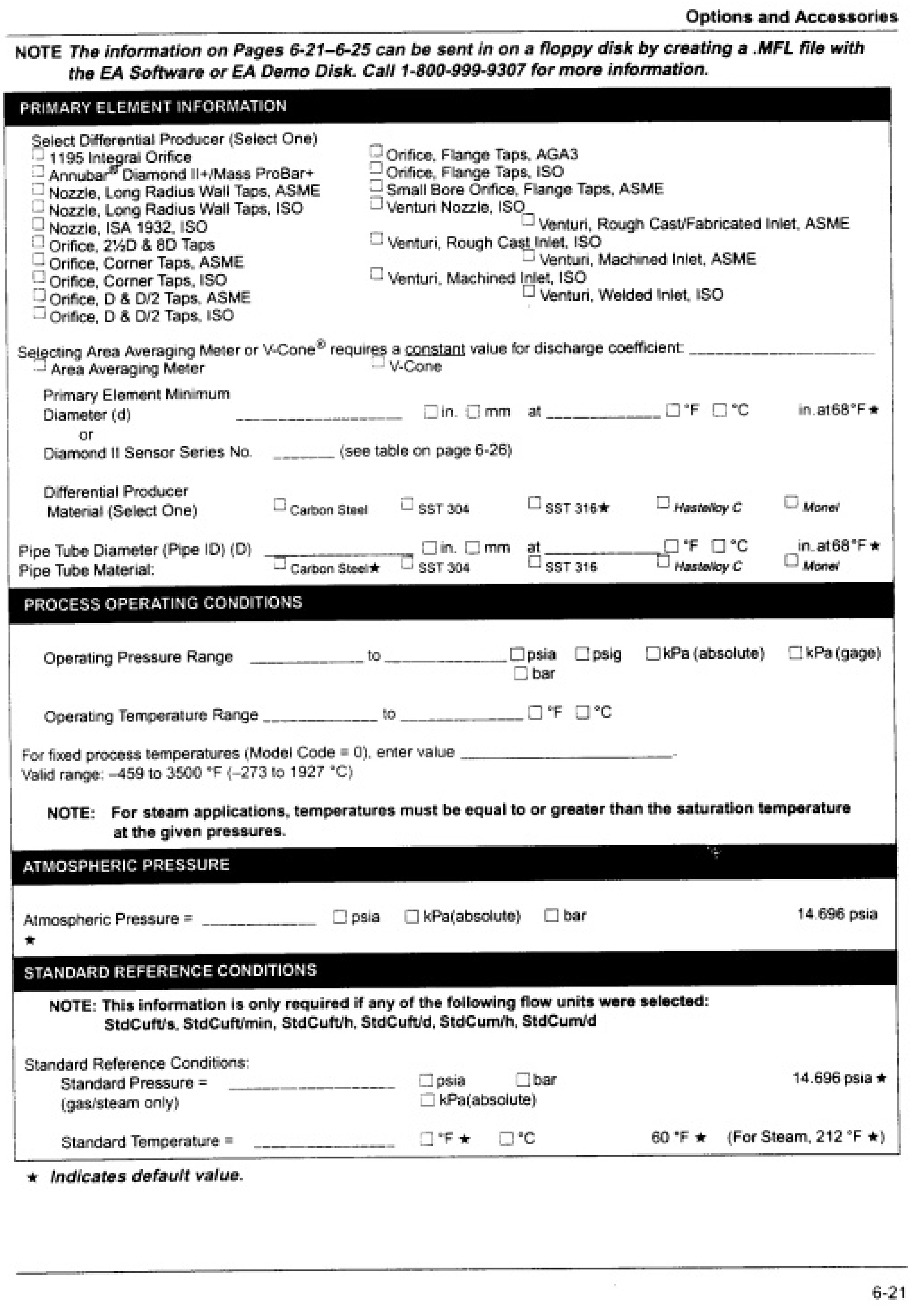
Static Pressure = _______________(0.864★)

(2) If absolute pressure module, then lower static pressure values must be ≥ 0.5 psia (3.45 kPa).

★ ***Indicates default value.***

6-20

Appendix B-1. Rosemount 3095 Installation and Setup Checks/Log Form
(continued)



Options and Accessories

NOTE ***The information on Pages 6-21–6-25 can be sent in on a floppy disk by creating a .MFL file with the EA Software or EA Demo Disk. Call 1-800-999-9307 for more information.***

PRIMARY ELEMENT INFORMATION

Select Differential Producer (Select One)
☐ 1195 Integral Orifice
☐ Annubar® Diamond II+/Mass ProBar+
☐ Nozzle, Long Radius Wall Taps, ASME
☐ Nozzle, Long Radius Wall Taps, ISO
☐ Nozzle, ISA 1932, ISO
☐ Orifice, 2½D & 8D Taps
☐ Orifice, Corner Taps, ASME
☐ Orifice, Corner Taps, ISO
☐ Orifice, D & D/2 Taps, ASME
☐ Orifice, D & D/2 Taps, ISO
☐ Orifice, Flange Taps, AGA3
☐ Orifice, Flange Taps, ISO
☐ Small Bore Orifice, Flange Taps, ASME
☐ Venturi Nozzle, ISO
☐ Venturi, Rough Cast/Fabricated Inlet, ASME
☐ Venturi, Rough Cast Inlet, ISO
☐ Venturi, Machined Inlet, ASME
☐ Venturi, Machined Inlet, ISO
☐ Venturi, Welded Inlet, ISO

Selecting Area Averaging Meter or V-Cone® requires a <u>constant</u> value for discharge coefficient: ____________________
☐ Area Averaging Meter ☐ V-Cone

Primary Element Minimum Diameter (d) ________________ ☐ in. ☐ mm at ____________ ☐ °F ☐ °C in. at 68 °F ★
or
Diamond II Sensor Series No. _______ (see table on page 6-26)

Differential Producer Material (Select One) ☐ Carbon Steel ☐ SST 304 ☐ SST 316★ ☐ *Hastelloy C* ☐ *Monel*

Pipe Tube Diameter (Pipe ID) (D) ________________ ☐ in. ☐ mm at ____________ ☐ °F ☐ °C in. at 68 °F ★
Pipe Tube Material: ☐ Carbon Steel★ ☐ SST 304 ☐ SST 316 ☐ *Hastelloy C* ☐ *Monel*

PROCESS OPERATING CONDITIONS

Operating Pressure Range ____________ to ____________ ☐ psia ☐ psig ☐ kPa (absolute) ☐ kPa (gage) ☐ bar

Operating Temperature Range ____________ to ____________ ☐ °F ☐ °C

For fixed process temperatures (Model Code = 0), enter value ______________________.
Valid range: –459 to 3500 °F (–273 to 1927 °C)

NOTE: For steam applications, temperatures must be equal to or greater than the saturation temperature at the given pressures.

ATMOSPHERIC PRESSURE

Atmospheric Pressure = ____________ ☐ psia ☐ kPa(absolute) ☐ bar 14.696 psia ★

STANDARD REFERENCE CONDITIONS

NOTE: This information is only required if any of the following flow units were selected: StdCuft/s, StdCuft/min, StdCuft/h, StdCuft/d, StdCum/h, StdCum/d

Standard Reference Conditions:
Standard Pressure = ________________ ☐ psia ☐ bar ☐ kPa(absolute) 14.696 psia ★
(gas/steam only)

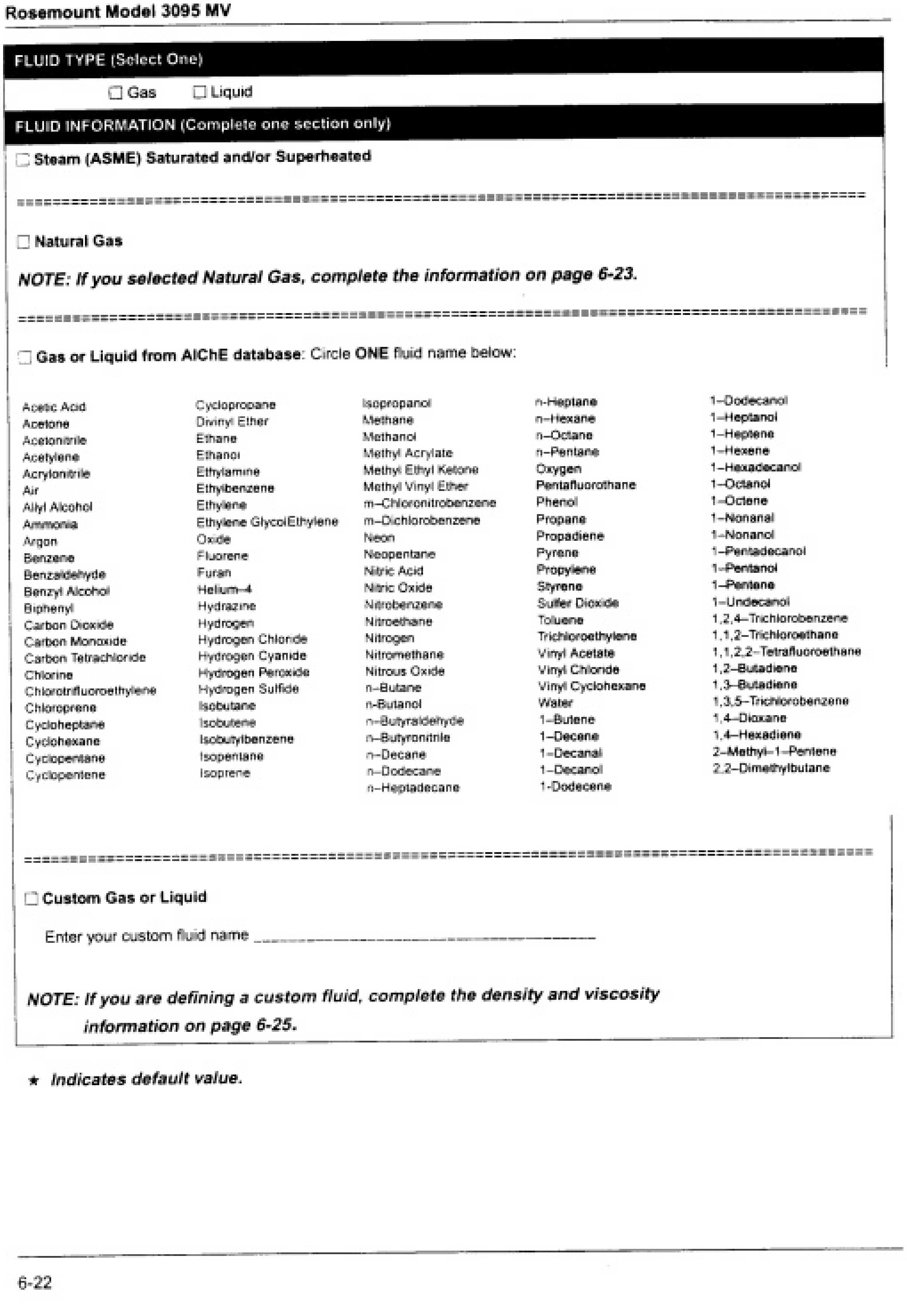
Standard Temperature = ______________ ☐ °F ★ ☐ °C 60 °F ★ (For Steam, 212 °F ★)

★ ***Indicates default value.***

6-21

Appendix B-1. Rosemount 3095 Installation and Setup Checks/Log Form

(continued)



Rosemount Model 3095 MV

FLUID TYPE (Select One)

☐ Gas ☐ Liquid

FLUID INFORMATION (Complete one section only)

☐ **Steam (ASME) Saturated and/or Superheated**

==

☐ **Natural Gas**

NOTE: If you selected Natural Gas, complete the information on page 6-23.

==

☐ **Gas or Liquid from AIChE database**: Circle **ONE** fluid name below:

Acetic Acid
Acetone
Acetonitrile
Acetylene
Acrylonitrile
Air
Allyl Alcohol
Ammonia
Argon
Benzene
Benzaldehyde
Benzyl Alcohol
Biphenyl
Carbon Dioxide
Carbon Monoxide
Carbon Tetrachloride
Chlorine
Chlorotrifluoroethylene
Chloroprene
Cycloheptane
Cyclohexane
Cyclopentane
Cyclopentene
Cyclopropane
Divinyl Ether
Ethane
Ethanol
Ethylamine
Ethylbenzene
Ethylene
Ethylene GlycolEthylene
Oxide
Fluorene
Furan
Helium–4
Hydrazine
Hydrogen
Hydrogen Chloride
Hydrogen Cyanide
Hydrogen Peroxide
Hydrogen Sulfide
Isobutane
Isobutene
Isobutylbenzene
Isopentane
Isoprene
Isopropanol
Methane
Methanol
Methyl Acrylate
Methyl Ethyl Ketone
Methyl Vinyl Ether
m–Chloronitrobenzene
m–Dichlorobenzene
Neon
Neopentane
Nitric Acid
Nitric Oxide
Nitrobenzene
Nitroethane
Nitrogen
Nitromethane
Nitrous Oxide
n–Butane
n-Butanol
n–Butyraldehyde
n–Butyronitrile
n–Decane
n–Dodecane
n–Heptadecane
n-Heptane
n–Hexane
n–Octane
n–Pentane
Oxygen
Pentafluorothane
Phenol
Propane
Propadiene
Pyrene
Propylene
Styrene
Sulfer Dioxide
Toluene
Trichloroethylene
Vinyl Acetate
Vinyl Chloride
Vinyl Cyclohexane
Water
1–Butene
1–Decene
1–Decanal
1–Decanol
1-Dodecene
1–Dodecanol
1–Heptanol
1–Heptene
1–Hexene
1–Hexadecanol
1–Octanol
1–Octene
1–Nonanal
1–Nonanol
1–Pentadecanol
1–Pentanol
1–Pentene
1–Undecanol
1,2,4–Trichlorobenzene
1,1,2–Trichloroethane
1,1,2,2–Tetrafluoroethane
1,2–Butadiene
1,3–Butadiene
1,3,5–Trichlorobenzene
1,4–Dioxane
1,4–Hexadiene
2–Methyl–1–Pentene
2,2–Dimethylbutane

==

☐ **Custom Gas or Liquid**

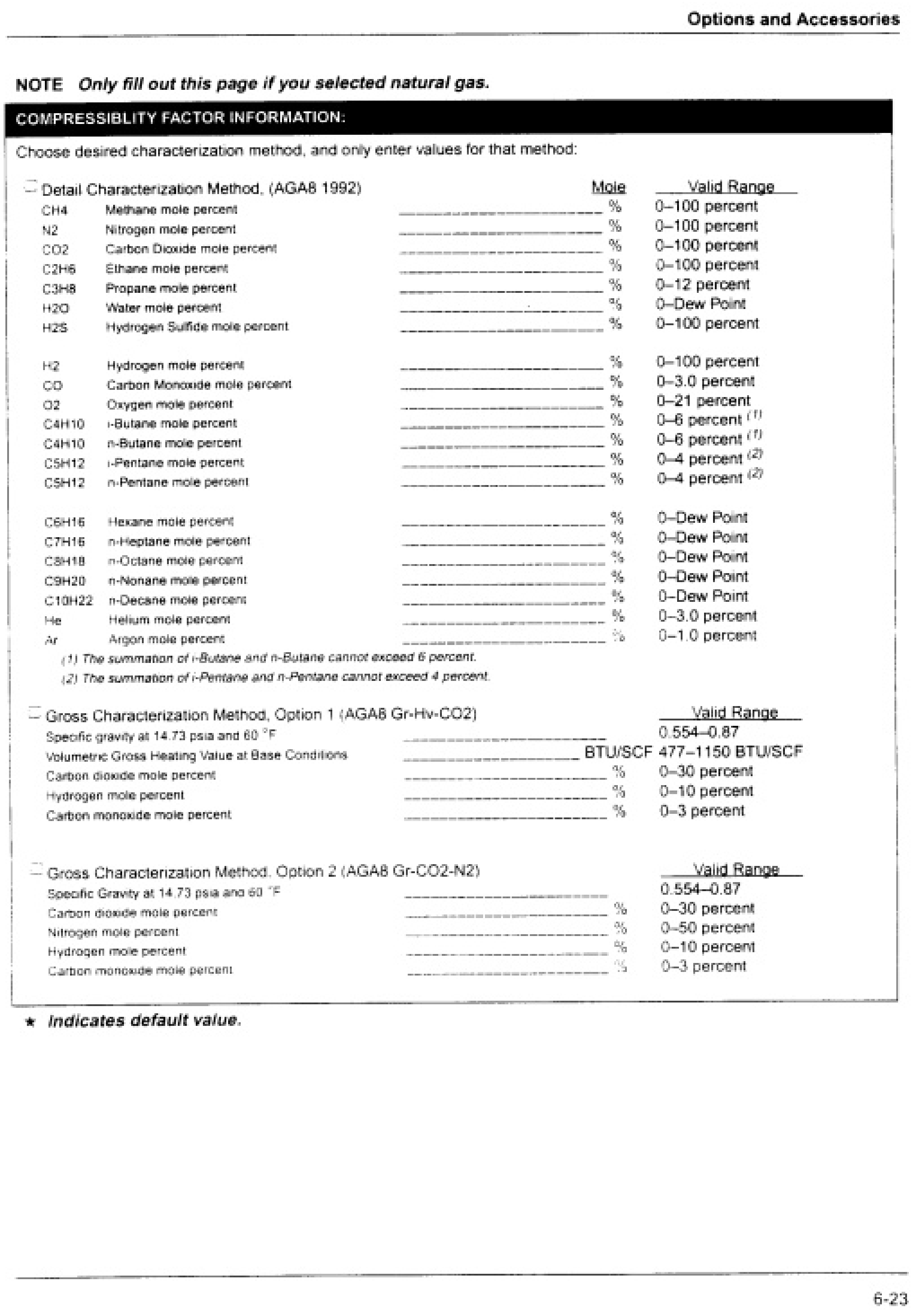
Enter your custom fluid name ______________________________

NOTE: If you are defining a custom fluid, complete the density and viscosity information on page 6-25.

★ ***Indicates default value.***

6-22

Appendix B-1. Rosemount 3095 Installation and Setup Checks/Log Form
(continued)



NOTE ***Only fill out this page if you selected natural gas.***

COMPRESSIBLITY FACTOR INFORMATION:

Choose desired characterization method, and only enter values for that method:

☐ Detail Characterization Method, (AGA8 1992)

			Mole	Valid Range
CH4	Methane mole percent	____________	%	0–100 percent
N2	Nitrogen mole percent	____________	%	0–100 percent
CO2	Carbon Dioxide mole percent	____________	%	0–100 percent
C2H6	Ethane mole percent	____________	%	0–100 percent
C3H8	Propane mole percent	____________	%	0–12 percent
H2O	Water mole percent	____________	%	0–Dew Point
H2S	Hydrogen Sulfide mole percent	____________	%	0–100 percent
H2	Hydrogen mole percent	____________	%	0–100 percent
CO	Carbon Monoxide mole percent	____________	%	0–3.0 percent
O2	Oxygen mole percent	____________	%	0–21 percent
C4H10	i-Butane mole percent	____________	%	0–6 percent (1)
C4H10	n-Butane mole percent	____________	%	0–6 percent (1)
C5H12	i-Pentane mole percent	____________	%	0–4 percent (2)
C5H12	n-Pentane mole percent	____________	%	0–4 percent (2)
C6H16	Hexane mole percent	____________	%	0–Dew Point
C7H16	n-Heptane mole percent	____________	%	0–Dew Point
C8H18	n-Octane mole percent	____________	%	0–Dew Point
C9H20	n-Nonane mole percent	____________	%	0–Dew Point
C10H22	n-Decane mole percent	____________	%	0–Dew Point
He	Helium mole percent	____________	%	0–3.0 percent
Ar	Argon mole percent	____________	%	0–1.0 percent

(1) The summation of i-Butane and n-Butane cannot exceed 6 percent.

(2) The summation of i-Pentane and n-Pentane cannot exceed 4 percent.

☐ Gross Characterization Method, Option 1 (AGA8 Gr-Hv-CO2)

			Valid Range
Specific gravity at 14.73 psia and 60 °F	____________		0.554–0.87
Volumetric Gross Heating Value at Base Conditions	____________	BTU/SCF	477–1150 BTU/SCF
Carbon dioxide mole percent	____________	%	0–30 percent
Hydrogen mole percent	____________	%	0–10 percent
Carbon monoxide mole percent	____________	%	0–3 percent

☐ Gross Characterization Method, Option 2 (AGA8 Gr-CO2-N2)

			Valid Range
Specific Gravity at 14.73 psia and 60 °F	____________		0.554–0.87
Carbon dioxide mole percent	____________	%	0–30 percent
Nitrogen mole percent	____________	%	0–50 percent
Hydrogen mole percent	____________	%	0–10 percent
Carbon monoxide mole percent	____________	%	0–3 percent

★ ***Indicates default value.***

Appendix B-2. Rosemount 3095 Sensor Function Checks/Log Form

Sensor function checks: A series of meter and transmitter function checks will be conducted before the verification period begins and again at the end of the testing. The following checks will be included.

- Power supply test to document that the facility DAS is supplying sufficient power (no less than 11 vDC) to the transmitter.
- Analog output checks where a current of known amount will be checked against a secondary device to ensure that 4 mA and 20 mA signals are produced.
- Reasonableness checks will be performed by ensuring that the mA signal produced at the transmitter is recorded correctly in the DAS.
- Zero checks will be conducted by isolating the transmitter from the differential pressure taps using valves built into the meter, and recording the transmitter output. The sensor output must read 0 flow during these checks.

Procedures for performing these checks are documented in the Product Manual. All records will be logged in the following form.

Appendix B-2. Rosemount 3095 Sensor Function Checks/Log Form

(continued)

SENSOR FUNCTION CHECKS

1) Analog Loop Test

Date ____________

Time __________ __________ __________ _______

Meter Output (mA) __________ __________ __________ _______

Master Reading (mA) __________ __________ __________ _______

% Difference __________ __________ __________ _______

Corrective Action ____

2) Analog Output to DAS Terminal

Date __________
Time ____________ ____________

Meter Output (mA) ____________ ____________

Meter raw data reading at DAS terminal (mA) ____________ ____________

% Difference ____________ ____________

Corrective Action ____

CALIBRATION CHECKS

1) Bench Calibration

Date ____________ Time ____________

Absolute Pressure Offset Trim Point (psi) __________________

Absolute Pressure Slope Trim Point (psi) __________________

Absolute Temperature Offset Trim Point (°F) __________________

Absolute Temperature Slope Trim Point (°F) __________________

Corrective Action ____

2) Zero Check

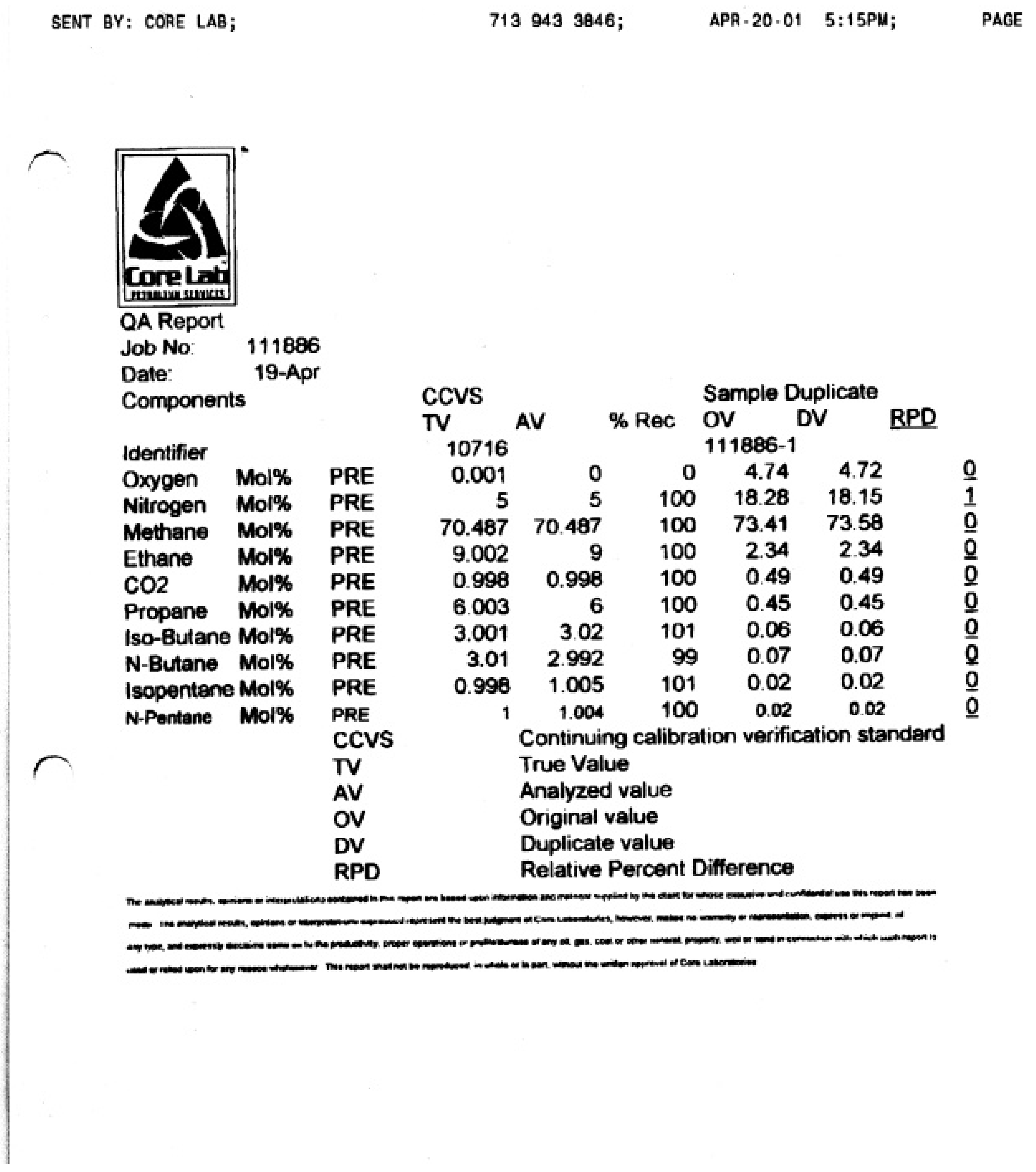
Date ____________ Time ____________

Initial reading ____________ mA ____________ lbs/hr

Reading after adjustment____________ mA ____________ lbs/hr (should be 0, enter n/a if no adjustment)

Corrective Action ____

Appendix B-3. Example of Core Laboratories Calibration Data



SENT BY: CORE LAB; 713 943 3846; APR-20-01 5:15PM; PAGE

Core Lab
PETROLEUM SERVICES

QA Report
Job No: 111886
Date: 19-Apr

Components			CCVS TV	AV	% Rec	Sample Duplicate OV	DV	RPD
Identifier			10716			111886-1		
Oxygen	Mol%	PRE	0.001	0	0	4.74	4.72	0
Nitrogen	Mol%	PRE	5	5	100	18.28	18.15	1
Methane	Mol%	PRE	70.487	70.487	100	73.41	73.58	0
Ethane	Mol%	PRE	9.002	9	100	2.34	2.34	0
CO2	Mol%	PRE	0.998	0.998	100	0.49	0.49	0
Propane	Mol%	PRE	6.003	6	100	0.45	0.45	0
Iso-Butane	Mol%	PRE	3.001	3.02	101	0.06	0.06	0
N-Butane	Mol%	PRE	3.01	2.992	99	0.07	0.07	0
Isopentane	Mol%	PRE	0.998	1.005	101	0.02	0.02	0
N-Pentane	Mol%	PRE	1	1.004	100	0.02	0.02	0

CCVS	Continuing calibration verification standard
TV	True Value
AV	Analyzed value
OV	Original value
DV	Duplicate value
RPD	Relative Percent Difference

Appendix B-4. Corrective Action Report

Corrective Action Report

Verification Title: ________________________________

Verification Description: __________________________

Description of Problem: _________________________________

____

____

____

Originator: _______ **Date:** ________

Investigation and Results: ______________________________

____

____

____

Investigator: _______ **Date:** ________

Corrective Action Taken: _______________________________

____

____

____

Originator: _______ **Date:** ________
Approver: _______ **Date:** ________

Carbon copy: GHG Center Project Manager, GHG Center Director, SRI QA Manager, EPA-APPCD Project Officer

APPENDIX C

Assessment of Composition Changes on Discharge Gas Flow Data Quality

Appendix C-1

Example Illustrating Compositional Effects on Discharge Gas Flow Measurements

Discharge gas composition depends on the vent gas composition and the motive gas/vent gas mixture ratio. Motive gas composition is expected to be consistent throughout the verification test because its source will be the pipeline-quality sales gas. As a result, vent gas composition is the primary contributing factor affecting the discharge gas compositions. According to an API/GRI study which directly measured vent gas composition from a South Texas oil/gas processing operation, CH_4 levels varied by ± 10 percent and C3+ compounds varied by ± 15 percent during a 4-day sampling period (API 1997). With the EVRU, this variability will be dampened because the motive gas will be diluted with vent gas in the EVRU.

The following example illustrates a hypothetical case in which vent gas compositional changes are occurring, and the effects these changes have on the discharge gas composition and flow measurements reported by the DAS. Three assumptions are made:

1. Assume baseline compositions are equivalent to the values shown in Table C-1. Baseline discharge gas composition is defined as the average composition of 6 samples collected prior to testing. This composition is entered into the discharge gas flow meter software, and is the basis upon which compensated flow computations are performed and reported in the DAS.

2. Assume motive gas composition is equivalent to the values measured by TFE on June 10, 2001, and does not change during testing (Table 2-4).

3. Assume vent gas composition changes equivalent to the values shown in Table C-1. The net effect on discharge gas composition is shown in the last column. For the verification, actual discharge gas composition will be obtained by collecting and analyzing 3 samples per week.

Table C-1. Effects of Varying Vent Gas on Discharge Gas Compositions

	Vent Gas Composition		Discharge Gas Composition	
Compound	**Baseline (Volume %)**	**Actual (Volume %)**	**Baseline[a] (Volume %)**	**Actual (Volume %)**
Methane	62.000	49.500	78.73	74.18
Ethane	13.233	11.233	9.14	8.41
Propane	8.381	11.381	4.58	5.67
Butanes	8.800	11.800	3.95	5.04
Pentanes	4.672	9.422	1.98	3.71
Hexanes	1.480	2.980	0.96	1.50
Heptanes	1.247	3.497	0.45	1.27
Nitrogen	0.187	0.000	0.12	0.05
Carbon Dioxide	0.000	0.187	0.10	0.17

[a] Used to configure the discharge gas flow meter. Flow rates recorded in the DAS are based on this composition

In this example, if the Field Team Leader were to program the flow meter with the baseline discharge gas composition at the beginning of testing, and the average composition was later determined to be equivalent to the actual discharge gas, actual flows would differ from those reported by the DAS. These differences are quantified by performing test calculations in the EA software at various operating conditions. Table C-2 summarizes the hypothetical flow meter output for flow rate ranging between 225 to 591 scfm or differential pressures across the orifice ranging between 20 to 150 inches water, respectively.

Table C-2. Comparisons Between Discharge Gas Flow Rates

Delta P (" H_2O)	Flow at Baseline Gas Composition (scfm)	Flow at "Actual" Gas Composition (scfm)	% Change
20	225.57	239.15	6.02
50	352.69	373.96	6.03
85	454.49	481.91	6.03
115	523.50	555.08	6.03
150	591.13	626.80	6.03

Note: These values represent flows at 30 psig gas pressure and 60 ^{o}F gas temperature.

If the discharge gas composition remains within the values shown in Table C-2 both prior to and during the test, then the maximum expected error due to compositional changes would be 6.0 percent. For these flow rates and conditions this error is independent of the magnitude in flow rate (i.e., delta P), and does not vary significantly with reasonable variations in gas temperature (60 to 80 ^{o}F) or gas pressure (20 psig). Section 3.2 uses the ± 6.0 percent error as the data quality indicator goal for compositional effects on discharge gas flow rates.

If the results of any one (1) discharge gas sample collected during testing indicate compositions that fall outside the range shown in Table C-2, the ± 6.0 error will not be representative. If this occurs, the GHG Center will compute the actual error achieved using procedures listed in Appendix C-2.

Appendix C-2

Procedures for Determining Discharge Gas Flow Rate Error
(When Discharge Gas Composition Falls Outside of Range Shown In Table C-2)

1. Using compositional results of samples taken prior to testing, compute average composition for each gas component. Enter this baseline composition into EA.

2. Determine average orifice differential pressure, average gas temperature, and average gas pressure from the data logged by the DAS for the first day a gas sample was collected. Enter these three averages into the EA. Record the flow rate calculated by EA for these operating conditions ($Q_{baseline}$).

3. Replace the baseline gas composition with actual gas composition for the first day a gas sample was collected. Record the flow rate calculated by EA for this composition (Q_{actual}).

4. Calculate percent change between baseline flow rate and actual flow rate.

   $\% \text{ Change} = (Q_{baseline} – Q_{actual}) / Q_{baseline} \times 100$

5. Repeat Steps 1 through 4 for each additional day during which gas samples were collected.

6. Calculate average change, and compute 90 percent confidence interval.

7. Compute maximum error achieved by adding the average change and the confidence interval (6.5+1.1 = 7.6 %). This error will be used to reconcile the gas recovery rate DQO in Section 3.2.

Example Calculation of Error Achieved

Testing Day When Gas Sample Was Collected	Daily Average Pressure Drop (“ H2O)	Daily Average Gas Pressure (psig)	Daily Average Gas Temperature (o F)	Computed Flow @ Actual Gas Composition (scfm)	Computed Flow @ Baseline Gas Composition (scfm)	% Change
1	20	30	60	245.00	225.57	7.9
3	50	30	60	373.96	352.69	6.0
5	20	30	60	239.15	225.57	6.0
8	85	29	65	455.00	485.00	6.2
					Avg.	**6.5**
					Standard Deviation	**0.9**
					$t_{.05, 3}$	**2.353**
					±	**1.1**
					Maximum Error Due to Compositional Change	**7.6**