A QUICK WORD ABOUT NOMENCLATURE

Since this report references both itself and the 21.1 standard, the following nomenclature has been adopted to make it clear which document is being referenced.

- **report** - references this document, the one you are now reading.
- **standard** references the 21.1 standard, unless otherwise noted.
- **section** and **subsection** both refer to portions of the API 21.1 standard.
- **document** is a generic term that could be referencing either document. Hopefully the context will make it clear which document is being referenced.

INTRODUCTION

In September of 1993 API published a new section of the Manual of Petroleum Measurement Standards titled **Chapter 21 Flow Measurement Using Electronic Metering Systems, Section 1 Electronic Gas Measurement**. This report provides an overview of the API 21.1 document with the intent of serving as a primer and something of an introduction to the publication.

The 21.1 standard was developed by representatives from the American Petroleum Institute (API), American Gas Association (AGA) and Gas Processors Association (GPA) member companies with input from equipment manufacturers and others. The 21.1 standard represents the first API publication in the field of electronic metering systems.

Work on the standard began much earlier than 1993 with initial meetings taking place as early as mid 1989. Early on, ground rules were established that served as mission statements guiding the efforts of all involved in the publication of the standard. Those ground rules are summarized as follows:

- The intent was to define such things as algorithms and audit trail requirements for using electronic flow computers and associated equipment for custody transfer.
- The intent was not to produce a comparative study between the accuracy of chart and electronic based systems.
- The intent was to address minimum requirements based on current technology, yet not circumvent the use of future, more capable technology or more stringently specified systems.
- The scope included both differential and linear meters. The scope originally included various types of hydrocarbon fluids, but in the interest of expediency, it was decided to treat different fluids individually, starting with gas and moving to liquids later. As of this writing, work is currently underway on API 21.2 Electronic Liquid Measurement.

API 21.1 CONTENTS

API 21.1 consists of nine major subsections, three appendices and 10 figures. The subsection titles are:

1. Introduction and Scope
2. Description of an Electronic Gas Measurement System
3. Referenced Publications
4. Electronic Gas Measurement System Algorithms
5. Data Availability
6. Audit and Reporting Requirements
7. Equipment Installation
8. Equipment Calibration and Verification
9. Security

The appendices are:

- B. Averaging Techniques
- C. Calibration and Verification Equipment

Subsection 1.1 – INTRODUCTION AND SCOPE

The major paragraph of the scope statement is as follows, “This standard describes the minimum specifications for electronic gas measurement systems used in the measurement and recording of flow parameters of gaseous phase hydrocarbon and other related fluids for production and transmission custody transfer applications utilizing industry-recognized primary measurement devices. For the purpose of this standard, electronic correctors of the type used on linear meters were not considered to constitute an electronic gas measurement system.”
Some notable elements of the scope are,

- Minimum specifications
- Gaseous phase hydrocarbon
- Production and Transmission applications
- Linear electronic correctors not considered

**Subsection 1.2 — ELEMENTS OF A GAS MEASUREMENT SYSTEM**

Main system elements presented in subsection 1.1 include:

- **Primary Device** is the basic meter run including the orifice plate, turbine, rotary or diaphragm meter.

- **Secondary Devices** are used for sensing such process variables as static pressure, differential pressure, temperature, and density.

- **Tertiary Device** is an electronic computer that is designed to correctly calculate flow and that can receive information from the primary and/or secondary devices.

Also introduced in subsection 1.2 are the concepts of transducers, transmitters and signal processing. In practice, transducer and transmitter are often used as synonymous terms. Strictly speaking, this is not correct and the standard attempts to provide instruction in this regard.

“Transducers respond to changes in the measured parameters with a corresponding change in electrical values. These devices are referred to as transmitters when they have been specifically designed to convert the transducer’s electrical output to a signal suitable for transmission over distances greater than could otherwise be achieved.”

Hybrid EGM systems currently exist which render the definitions of these traditional terms (secondary devices, tertiary devices, transducers and transmitters) inadequate as descriptors of the systems’ components. These hybrid systems have evolved to lower cost and decrease uncertainties.

Several different configurations are currently in use. For example, some flow computers interface to standard 1-5Vdc or 4-20ma external transmitters. Others interface directly to transducer low level analog signals, while yet other flow computers connect directly to newer digital transducers using either serial or parallel techniques. Sometimes the transducers share electronics with the flow computer and both reside in the same enclosure.

Add to this the concept of smart transducers/transmitters and yet another set of scenarios exists. Smart transducers/transmitters generally provide lower measurement uncertainties by digitally compensating for temperature and pressure effects on the transducer’s sensing elements and associated components.

Usually, smart transducers/transmitters perform compensation algorithms internally and provide compensated values to the flow computer, but some system designs rely on the flow computer to perform transducer compensation algorithms.

Therefore, in addition to the traditionally defined terms, the 21.1 standard attempts to allow all these configurations by including statements such as “The tertiary and secondary devices, as well as the primary device, may be contained in one or more enclosures, or packaged separately.” And in another statement, “The electronic flow computer has no effect on the accuracy of either the primary or the secondary device, except where characterization may be performed.”

Subsections 1.2.2 and 1.2.3 define terms and symbols used throughout the document. Subsection 1.3 references publications cited within the 21.1 standard. These sections are not reviewed in this paper.

**Subsection 1.4 – ELECTRONIC GAS MEASUREMENT SYSTEM ALGORITHMS**

Subsection 1.4 defines algorithms for both differential and linear measurement systems. Only differential systems are presented in this report.

The standard defines component algorithms that, when applied as recommended, collectively result in a composite algorithm suitable for computing a desired quantity such as mass, energy or volume. These algorithms are not intended to supplant already published work. Instead the standard references other equation standards when possible. Only generalized equations germane to the topic at hand were included in the 21.1 standard.

The primary goal of subsection 1.4 is to define the minimum acceptable frequencies for solving equations and measuring inputs to those equations.

**1.4.2 Differential Meter Measurement**

In differential metering, a total quantity (volume, for example) is determined by integration of a rate equation (AGA3 / API 14.3, for example) over a specified time interval. The equation form of this integration operation is presented in the 21.1 standard as:

\[
Q_t = \int_{t_0}^{t} qt \ast dt
\]

where,

\[
\int_{t_0}^{t} = \text{integration operation from time } t_0 \text{ to time } t
\]

\[
Q_t = \text{quantity accumulated between time } t_0 \text{ and time } t
\]

\[
qt = \text{rate equation for quantity per unit of time}
\]

\[
dt = \text{delta time between integration samples}
\]

For illustration purposes, this report assumes the rate equation of eq 1 is based on AGA3/API 14.3. The 21.1
standard allows this rate equation to be factored into two component algorithms that can be solved on two different time domains. This is loosely related to the older AGA3 rate equation that often was described by two component algorithms as:

\[ Q_h = C' \times \text{Extension} \]  

(eq 2)

where,

\[ Q_h = \text{Flow Rate (cubic feet / hour)} \]

\[ C' = Fb \times Fr \times Y \ldots \]  

(one component)

\[ \text{Extension} = \sqrt{Hw \times Pf} \]  

(second component)

Since the new AGA3/API 14.3 standard no longer uses the older \([C' \times \text{Extension}]\) paradigm and since the 21.1 standard’s algorithms were to generically discuss time domain issues rather than re-state equations in other standards, new terms were introduced to discuss the time domain issues. Those terms are:

\[ \text{imp} \] = Integral Multiplier Period, a unit of time for specifying the frequency for performing a complete volume calculation.

\[ Q_{\text{imp}} \] = Quantity (volume) accumulated for the integral multiplier period.

\[ IV_{\text{imp}} \] = Integral Value, one of the two components of the flow rate equation (like the older Extension).

\[ IMV_{\text{imp}} \] = Integral Multiplier Value, the second component of the flow rate equation (like the older \(C'\)). \(IMV_{\text{imp}}\) is the value resulting from the calculation of all other factors of the flow rate equation not included in \(IV_{\text{imp}}\).

Using these new terms, the volume algorithm is presented in the 21.1 standard as:

\[ Q_{\text{imp}} = IMV_{\text{imp}} \times IV_{\text{imp}} \]  

(eq 3)

Where \(IV_{\text{imp}}\) is the portion of the flow rate equation that must be integrated on relatively fast time periods, and \(IMV_{\text{imp}}\) is the portion of the flow rate equation that can be computed on a slower time period, the Integral Multiplier Period.

Four minimum acceptable criteria are established in subsection 1.4 of the 21.1 Standard. They are:

- The \(IV_{\text{imp}}\) component of the flow rate equation shall be calculated and summation performed at least once per second. It is further recommended that the sampling frequency and the integral value calculation frequency be performed at the same time interval.

- The Integral Multiplier Period, the period at which \(IMV_{\text{imp}}\) and \(Q_{\text{imp}}\) are computed, shall not exceed one hour. An Integral Multiplier Period of less than one hour shall be such that an integral (whole) number of multiplier periods occurs during one hour.

Putting all this together into a composite algorithm results in:

\[ Q_{\text{imp}} = IMV_{\text{imp}} \times \int_{t0}^{t_{\text{imp}}} IV_{\text{imp}} \, dt \]  

(eq 4)

where,

\[ \text{imp} \] = Integral Multiplier Period of time period not to exceed one hour.

\[ dt \] = integration period not to exceed one second

\[ IV_{\text{imp}} = \sqrt{Hw \times Pf}, \] at a minimum

\[ IMV_{\text{imp}} \] = the remainder of the flow rate equation not included in \(IV_{\text{imp}}\).

**Rans Methodology**

For all timing requirements mentioned in section 1.4, slower periods can be used if they can be qualified as acceptable. The 21.1 standard provides a tool to help conduct this qualification process. This tool is included in appendix A and is called the **Rans Methodology**.

The **Rans Methodology** is a statistical evaluation method, developed by Mr. Rick Rans, to estimate the maximum amount of measurement uncertainty that exists for any given flow pattern across an orifice plate or linear type meter.

**First**, The **Rans Methodology** evaluates the uncertainty as a function of both flow pattern and calculation frequency. **Second** an evaluation of the additional uncertainty resulting from doing portions of the flow rate calculation using averages is conducted.

A detailed analysis based on the **Rans Methodology** is beyond the scope of this report.

**Averages**

Portions of the \(IMV_{\text{imp}}\) equation, such as expansion factor and compressibility, are dependent on the dynamic input variables.

Since \(IMV_{\text{imp}}\) can be computed on a time period slower than the dynamic input variables are sampled, the dynamic input variables must be averaged over the
longer time period. The 21.1 standard allows four different types of averages.

These averages are described algorithmically in appendix B of the standard. They are:

- Flow-dependent time-weighted linear
- Flow-dependent time-weighted formulaic
- Flow-weighted linear
- Flow-weighted formulaic

Flow dependent means that each sample is used to update the average's accumulator only during times of flow. Therefore, each sample’s contribution to the average is turned on and off as a function of the presence of flow resulting in an average during times of flow.

Flow weighted means that each sample in the average's accumulator is multiplied by the flow rate at the time the sample is taken. Therefore, each sample's contribution to the average is weighted by the flow rate. This is an interesting concept, since the flow rate isn't really known until some time later (the integral multiplier period). Therefore, the flow rate used in this case is some approximation of the actual flow rate.

Linear means that each sample in the average's accumulator is simply applied in engineering units. (e.g., PSI for pressure, Degrees F for temperature, in. H2O for differential pressure).

Formulaic means that each sample in the average's accumulator is applied as a function of the form of the primary element's fundamental equation. Thus, for differential meters the square root of each sample is taken before addition takes place. For linear meters, each sample is simply added in engineering units.

Low Flow Detection

As indicated by the term flow dependent above, deciding when there is and when there is not flow is something the EGM is expected to do.

If everything was perfect and stayed that way, there would be no need for special low flow detection logic. A differential pressure of zero would mean no flow and that would be the end of it.

The reality is that things, such as transducer calibration, drift and therefore a need to define an artificial zero (low flow cutoff point) exists.

Therefore, the 21.1 standard mentions this requirement in subsection 1.4.2.3 Low Flow Detection by simply stating, “A low flow cutoff point for differential meters should be determined by the contractually concerned parties based upon realistic assessment of site conditions.”

1.5 DATA AVAILABILITY

Subsection 1.5 defines data availability requirements for both differential and linear measurement systems. Only differential systems are presented in this report.

Although many people think the 21.1 standard applies only to electronic, remote, battery operated devices that compute rates and quantities, the 21.1 standard’s authors did not intend to limit the scope that much. The authors intended to write a standard that applied to systems of various acceptable configurations and, as such, they intended to allow rates and quantities to be computed in office systems too. They also allowed for portions of the audit trail to be constructed of either electronic or hard copy records. This subsection and the next (1.6 Audit and Reporting Requirements) reflect this intention more than anywhere else in the standard. These two subsections (1.5 and 1.6) are closely related and frequently restate the same requirements from different perspectives and in different ways.

1.5.1.1 Differential Meter On-site Calculations

This subsection describes information that must be available on-site, or be collectable on-site with a portable data collection device. For the most part, subsection 1.5 is a succinct itemization of required data items, most of which are as follows:

- 1.5.1.1.1, Historical data spanning the time since the last completed data collection period including, but not limited to the following:
  - At least hourly average values for temperature, pressure and differential pressure. Also, relative density, energy content, composition and density, if they are live inputs.
  - At least hourly quantity totals.
  - Dates and times for all averages and totals.
  - Total quantity accumulated during each contractually specified measurement period.
- 1.5.1.1.2, Input variable values affecting measurement such as meter run reference diameter (Dr), orifice bore reference diameter (dr), the calibrated span of the pressure, differential pressure and temperature transducers.
- 1.5.1.1.3, Instantaneous readings or displays for the live values of pressure, differential pressure, temperature, flow rate, accumulated quantity and alarm conditions. Other live inputs (such as density) shall be available if used.
- 1.5.1.1.4, An electronic or hard copy record including, but not limited to:
• “As found” and “As left” equipment calibration values.

• Old and new values for changes to any input variable that will affect the calculated quantities.

• A summary of alarm or error conditions affecting measurement.

• A daily summary indicating the hours or percentage of time for flow or no flow.

• The date and time of all events in the record shall be identified chronologically.

1.5.1.1 Differential Meter Off-site Calculations

• Data required on-site includes, but is not limited to:

  1.5.1.2.1, Instantaneous readings or displays for the live values of pressure, differential pressure, temperature, flow rate, accumulated quantity and alarm conditions. Other live inputs (such as density) shall be available if used.

  1.5.1.2.2, The unique identification number of the metering system.

  1.5.1.2.3, Data required off-site includes, but is not limited to the same data as is required in 1.5.1.1 (on-site calculations) with the exception of 1.5.1.1.3.

  1.5.1.2.4, Indications of alarm or error conditions shall be available off-site.

1.6 AUDIT AND REPORTING REQUIREMENTS

Subsection 1.6 defines audit and reporting requirements for both differential and linear measurement systems. Only differential systems are presented in this report.

Some key elements of the introduction to subsection 1.6 include:

• The audit trail shall include, but is not limited to, transaction records, configuration logs, event logs, corrected transaction records and field test reports.

• The records and reports in this section may be created on-site, off-site or a combination of both.

• The primary reason for retaining historical data is to provide support for the current and prior quantities reported.

• The data specified in this subsection will provide sufficient information to apply reasonable adjustments when the electronic gas measurement system has stopped functioning; is determined to be out of accuracy guidelines; or measurement parameters are incorrectly recorded.

Within the introduction of subsection 1.6 some new terms, such as quantity transaction record and event log are used. Most of the succeeding paragraphs in subsection 1.6 are devoted to defining these terms and the minimum acceptable data that composes the data records to which this term refers.

1.6.2 Quantity Transaction Record

“The quantity transaction record is the set of historical data and information supporting the quantity or quantities of volume, mass, or energy. The quantity transaction record is to be identified by a unique alphanumeric identifier denoting a specific electronic metering device and primary device.”

1.6.2.1 Daily Quantity Transaction Record for Differential Meters

This subsection itemizes the data elements that, at minimum, must be included in the daily record. They are:

• date period
• time
• quantity
• flow time
• differential pressure average
• flow temperature average
• static pressure average
• relative density average (if live)

Although flow integral is not required, it is stated that, in certain situations, it can provide valuable information.

When do Day's begin and end?

The daily quantity transaction record is the average or summation of data collected during a contract day. One daily quantity transaction record ends and a new one begins:

• Once, at the end of each contract day
• Any time one or more constant flow parameters are changed

1.6.2.3 Hourly Quantity Transaction Record for Differential Meters

This section itemizes the data elements that, at minimum, must be included in the hourly record. They are:
- date period
- time
- quantity
- differential pressure average
- flow temperature average
- static pressure average
- relative density average (if live)

Although flow integral is not required, it is stated that, in certain situations, it can provide valuable information.

**When do hours begin and end?**

The hourly record is the average or summation of data collected and calculated during a maximum of 60 consecutive minutes. One hourly quantity transaction record ends and a new one begins,

- Once, at the end of each hour
- Any time one or more constant flow parameters are changed

There are 24 hourly quantity transaction records for each contract day plus additional quantity transaction records for each time one or more constant parameters are changed.

**1.6.3 Algorithm Identification**

An algorithm identifier is to be provided to identify the calculations performed by the system. This can be provided in various ways, such as a software or manufacturer's version code.

**1.6.4 Configuration Log**

This log is to contain and identify all constant flow parameters used by the system to generate quantity transaction records. The 21.1 standard provides a table of elements that must be in the configuration log. As always, this is a minimum acceptable list that can be expanded on.

For differential meters, this table contains such things as,

- Meter Identifier
- Date and Time
- Contract Hour
- Atmospheric Pressure (if appropriate)
- Pressure Base
- Temperature Base
- Meter Tube Reference Inside Diameter
- Orifice Plate Reference Bore Diameter
- Etc.

**1.6.5 Event Log**

Each time a constant flow parameter (see 1.6.4 above) that can affect the quantity transaction record is changed, the old and new value, along with the date and time of the change, shall be logged.

The date and time of all events in the log shall be identified chronologically.

**1.6.6 Corrected Quantity Transaction Record**

With this subsection, the 21.1 standard recognizes that adjustments to original quantity transaction records are sometimes necessary, and specifies the data to be kept when this occurs. The need to make these changes results from:

- Constant flow parameters were not available at the time of calculation
- Constant flow parameters were found to be in error at a later date
- Dynamic flow parameters were found to be in error at a later date, usually due to:
  - calibration error
  - transducer failure
  - adverse operating conditions

The corrected quantity transaction record reflects changes to the original constant and/or dynamic flow parameters used in the calculation of the final quantity transaction record. The purpose of the record is to:

- identify reasons for all corrections
- provide the original and corrected constant and dynamic parameters used
- to clarify the adjusted quantities to be applied to the meter and quantity accounting statements

The original quantity transaction record is to remain intact as a permanent record. This original record, in combination with the most recent corrected quantity transaction record, provides a detailed tracking of the custody transfer quantities.

The next two subsections pertain, for the most part, to installation, verification and calibration of the secondary devices. Since many people are already familiar with these devices, a detailed description is not presented here. In lieu of this, an outline of the next two subsections of the 21.1 follows,

**1.7 EQUIPMENT INSTALLATION**

1.7.1 Transducer/Transmitters
1.7.2 Gauge/Impulse Lines
1.7.3 EGM Devices and Assoc. Communications
1.7.4 Peripherals
1.7.5 Cabling
1.7.6 Commissioning

**1.8 EQUIPMENT CALIBRATION AND VERIFICATION**

1.8.1 Scope
1.8.2 Devices Requiring Calibration/Verification
1.8.3 Calibration and Verification Procedures
   1.8.3.1 Pressure and Temperature Devices
   1.8.3.2 Pulse Counters
   1.8.3.3 Analyzers
   1.8.3.4 Densitometers and Gravitometers
1.8.4 Frequency of Verification
1.8.5 Ambient Temperature and Pressure Effects
1.8.6 Calibration and Verification Equipment

1.9 SECURITY

1.9.1 Access — This subsection restricts access to the metering system to the owner or the owner’s contractually designated representative for the purpose of calibrating or altering the function of the metering system.

1.9.2 Restricting Access — States that the system should deny unauthorized access for the purpose of altering any input variables that may affect measurement. A unique security code of at least four characters is to be provided in support of this requirement. Instead of a security code, other measures, including mechanical, may be used to restrict access. A security code may also be used to grant access for the purpose of collecting data.

1.9.3 Integrity of Logged Data — Restates the requirement for an event log and calibration reports.

1.9.4 Algorithm Protection — Changing the algorithms used to calculate quantities is to be protected even more rigidly than the restriction method described in paragraph 1.9.2. Field operations and accounting office personnel are not to be authorized to change these algorithms.

1.9.5 Original Data — Simply states that there shall be no changes to the original data.

1.9.6 Memory Protection — This subsection requires a backup power supply, or nonvolatile memory, capable of retaining all data in the unit’s memory for a period not less than the normal data collection interval for the unit.

1.9.7 Error Checking — Simply states that an effective system of error checking shall be utilized each time data is transferred from one data storage device to another and that detected errors shall prevent the use of incorrect data.

CONCLUSION

Being the first of its kind, the 21.1 standard probably has room for improvement. However, considering the issues being dealt with, it is a very good initial effort. It
should provide valuable guidelines for evaluating Electronic Gas Metering Systems for Custody Transfer.

Although not a complete treatment of the 21.1 standard, it is hoped this report will serve as an adequate introduction to it. Time and space did not allow linear meter presentation within this report. However, the linear meter subsections within the 21.1 standard are presented with the same level of detail as are the differential meter subsections. Perhaps a sequel to this report, including the linear meter presentation will be forthcoming.

If you are interested in receiving a copy the API 21.1 standard it can be ordered from the American Petroleum Institute. When ordering, refer to Chapter 21.1, Electronic Gas Measurement, First Edition, August 1993, Order No. 852-30730.