Technical Review of Western Climate Initiative Proposals to Meter Fuel and Control Gas

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I. Executive Summary

The Western Climate Initiative (WCI) makes the assumption that Operators would be reporting the "most accurate" volumes if the gas was metered as a "fuel" stream and a "control" stream instead of applying theoretical factors and Engineering approaches to estimate these volumes. The reports make this assertion without discussing the technology that would be deployed to measure these streams to "provide the rigor required for either cap-and-trade or offset programs". The review below categorically rejects their basic assumption and asserts that the act of installing meters on the streams considered will provide a **false sense of security** and a **net deterioration in the quality of data reported**.

There is no gas measurement technology currently existing that would provide better data in the field than is currently being reported using manufacturer's numbers and theoretical calculations. In addition to making the data less representative of reality, the costs that would be imposed are staggering—industry would be required to spend billions of dollars to report gas emissions data that is demonstrably worse than the data they are reporting today.

A. Summary Expenditures

The "Per Company" column below assumes 2,000 wells per company, "Total WCI" column assumes 100,000 wells affected in the WCI States and Provinces (breakdown is included under "Cost of Implementation" below). Many wells cannot sustain either the increased operating cost or the capital expenditure so they would be plugged instead of spending this money—there is no way to predict this mix of expenditure vs. plugging.

	Per well (\$k)	Per Company (\$million)	Total WCI (\$million)
RTU Replacement	\$3.5	\$7	\$350
Host/Database		\$15	\$750
Site Modifications	\$30.0	\$60	\$3.000
Total Capital	\$33.5	\$82	\$4,100
Annual Operating Costs	\$1.5	\$3	\$150

B. Author Biography

David Simpson has 30 years experience in Oil & Gas and is currently the Proprietor and Principal Engineer of MuleShoe Engineering. Based in the San Juan Basin of Northern New Mexico, MuleShoe Engineering addresses issues in Coalbed Methane, Low Pressure Operations, Gas Compression, Gas Measurement, Field Construction, Gas Well Deliquification, and Produced Water Management.

A Professional Engineer with his Master's degree, David has had numerous articles published in professional journals, has contributed a chapter on CBM to the 2nd edition of <u>Gas Well Deliquification</u>, by Dr. James Lea, et al, and has spoken at various conferences, including the 2003 SPE *Annual Technical Conference and Exposition* in Denver. He has been a featured speaker at the bi-annual *Four Corners Oil & Gas* Conference for the last 6 years and is a regular instructor at short courses at the annual ALRDC *Gas Well Deliquification Workshop* in Denver. David was Program Chair for the highly successful SPE Advanced Technology Workshop titled "Managing the Performance of Low Pressure Gas Wells and Associated Facilities" held in Ft Worth, TX in October, 2008. His consulting practice includes clients in 10 countries.

II. Discussion

The Western Climate Initiative has developed at least two documents that each reach the conclusion that gas consumed on wellsites must be measured to achieve adequate "accuracy" in accounting for emissions. The documents further require that gas used for pneumatic controls must be measured separately from gas burned because vented gas has a different "emissions factor" on the environment than burned gas has.

The industry has long said and demonstrated that measuring either fuel gas or control gas represents a very large cost for a very small return. The discussion below supports that position.

A. Magnitude of Gas Consumed

1. Engine Fuel

The industry has an excellent understanding of engine fuel. Where engine fuel is measured, the theoretical correlations match very well with measured data. The added value of measuring this fuel-gas stream is not clear to most wellhead compressor operators; consequently it is rare to see a fuel meter on a wellhead compressor or pump jack. The various stakeholders in the gas production process (including regulatory agencies and mineral owners) have accepted that these volumes are both small and adequately represented by the theoretical usage factors.

Engines utilized in field locations range from a single-cylinder Arrow running a pump jack (smallest is the Arrow C-46 which is rated at 6 hp at 500 rpm at sea level with 70,000 BTU/hp-hr fuel consumption) to a nominal 1,000 hp compressor (such as the Waukesha P48 GLD which is rated at 1,200 hp at 1,400 rpm at sea level with 7,720 BTU/hp-hr fuel consumption). This equates to a required measurement range of 5 MCF/day to 220 MCF/day (3.5 to 153 SCFM) assuming a pump jack at ¹/₂ load and a GLD at full load.

2. Separator/Tank Heaters

I recently did a review of 536 tank and separator burners in the San Juan Basin. Burner nameplate capacity ranged from 50,000 BTU/hr to 500,000 BTU/hr. The average capacity was 340,000 BTU/hr. Since these burners only operate 5-6 months out of the year, this number equates to less than 170,000 BTU/hour on an annual basis. For some perspective, the ondemand hot water heater in my house is rated at 185,000 BTU/hour. This is a fair comparison since both devices are classed as "on demand" in that they will each turn off when conditions warrant—while in service, tank heaters only run a fraction of the time to maintain the tank at the set temperature.

The current method of reporting fuel consumed in burners is to determine if the heater had gas to it during the month, if it did then most operators take the nameplate energy consumption times 24 hours per day for every day of the month. For a 340,000 BTU/hour burner this equates to 253 MMBTU in a 31 day month. I have worked with several operators who would report this number even if the burner only had gas to it for a single day.

In reality, the water or condensate entering a tank is usually substantially warmer than the burner set point so the burner will tend to run less than 15 minutes out of an hour on the coldest night. This means that if you shut your heater down at noon on April 1 you would have burned 1 MMBTU for the month and reported 253 MMBTU. Even if the burner has gas to it for an entire month, you burn the gas in the pilot for 744 hours in a 31 day month (typical pilot lights burn approximately 1,700 BTU/hr), but you only run the main burner for something like 186 hours—for a 340,000 BTU/hr burner you consume less than 70 MMBTU and report 253 MMBTU.

The main challenge of measuring the gas consumed in a burner is that the device must measure the pilot flow with the same level of uncertainty as you apply to the main burner flow. For a common 500,000 BTU/hr burner this means that you have to have a 294:1 "turndown ratio". Turndown ratio is a measure of ability of a measurement device to provide similar "accuracy" over the expected operating range. According to Wikipedia, a Square Edged Orifice meter has a turndown ratio of 3:1. Even a Diaphragm Meter (similar to residential gas meters) only has a turndown ratio on the order of 80:1. A meter that can measure full burner flow would register zero with pilot flow.

With burner on/off control, there is a rapid transient in the flow as the line fills upstream of the burner followed by steady flow. A device that could successfully capture both the transient and the steady flow would have to be able to go from "off " to the top end of its range in less than 1 second, and then hold steady for up to 15 minutes, then go to zero in a fraction of a second. There is so much uncertainty in this transient flow that any available gas measurement technology would yield a worse result than manufacturer's estimates and Engineering calculations.

Required measurement range 0.04 to 12 MSCF/day (0.02 to 8.3 SCFM).

3. Dehydrator Reboilers, Heater/Treaters, and Line Heaters

These devices are similar in specific energy-use to the tank/separator heaters, but they tend to run continuously.

Dehydrators are used to remove water-vapor from a gas stream. This water vapor is adsorbed to a liquid that must then be regenerated. Regeneration takes place in a reboiler that is used to add enough heat to the liquid to cook the water out (about 8,000 BTU/lbm of water on average). Since "rich" liquid (i.e., liquid containing high levels of water) is continuously entering the reboiler, the heater is always on.

Both Heater/Treaters and Line heaters are designed to add heat to a process stream to control a process variable. For example, Line Heaters are often used in waxy crude to prevent precipitation of paraffin in the pipe causing a clogged line. A Heater/Treater is used to flash light hydrocarbons for further processing into Natural Gas and Natural Gas Liquids streams. Both of these classes of equipment have burners on the high end of the expected range for tank/separator heaters, and both operate around the clock, year-round.

Many technologies could be used to meter any of these streams with adequate repeatability and uncertainty. Whether you meter this stream or use engineering calculations, you will get very similar volumes burned.

4. Pneumatic devices

I did a study in the year 2000 (see SPE 61030) that quantified the gas used in high-bleed pneumatic devices. The project described in that paper was an economic success because we were able to replace high-bleed CEMCO throttling level-controllers with no-bleed, snap acting level controllers. The replacement controllers were markedly less effective, but they were marginally good enough and we were able to sell the gas that would have been vented in the CEMCO.

When talking about controllers (level, temperature, etc.), there are two parameters that have to be clarified: (1) Signal Type and (2) Bleed characteristics. Signal type is either "Throttling" or "Snap Acting". Bleed characteristic is either "continuous bleed" or "no bleed" An example of a Continuous Bleed, Throttling controller is shown below



In this device, supply gas is provided through a restrictive orifice to the vent. As the block (attached to a level float for example) descends, it begins restricting the flow through the vent and sends pressure to the controlled device (a motor valve in this case). The beauty of this device is that it operates the controlled device very gently and tends to produce very stable performance. The downside is that you are venting gas anytime that the controlled device is other than fully open. Since many controlled

devices are shut most of the time (e.g. in the referenced study, we determined from a sample of over 4,000 wells that the average well cycled the separator dump valve 5 times per hour for 3 minutes each cycle) some operators have tried to reduce the amount of vented gas by turning the process over like:



In this case, the block closes the vent most of the time. When the fluid level increases, the vent opens some. When the vent is opened far enough to drop the pressure on top of the pilot below the spring setting, the pilot snaps open and sends gas to the motor valve very rapidly. At the end of the cycle, the pilot goes shut and vents the motor valve through the top valve seat. Instead of venting for 45 minutes each hour, it vents about 15 minutes per hour at the cost of throttling the flow.

A "No Bleed" controller would look something like:



This simplified example shows that when the float is down, the supply valve is shut tight and the vent valve is open. As the float starts rising, the

vent is closed. As it continues to rise it reaches a point where the spring tension is inadequate to hold the supply valve shut and it "snaps" open. At the end of the cycle the falling float reaches the point where it can close the supply. As it continues to fall it eventually reaches the point where the vent opens and the motor valve shuts. Most snap acting controllers are applied in service this simple and it is rare to require a pilot in this on/off service.

Notice in the description of the action of the no-bleed controller, the supply gas us used to operate the valve against a dead-end. At the end of the process the supply is shut off before the vent opens. The only gas that is vented in a no-bleed controller is the volume of the piping and the motor-valve bonnet. The supply system is never directly exposed to an open vent, so there is no ongoing "bleeding" of gas.

It is possible to throttle a controlled device with a no-bleed controller with an external pilot, but the control tends to be poor and can't be controlled very long (i.e., the devices used to sense an intermediate position are cumbersome and tend to have a "jerky" action). For practical purposes, when you decide to go to no-bleed you are locking the device into snap acting.

Continuous-bleed controllers are reasonably easy to meter the gas (a CEMCO continuous bleed, throttling level controller vents about 800 SCF/day at 35 psig supply pressure assuming that it is not venting or is venting at a reduced rate for 15 minutes per hour).

For a no-bleed controller, each time the dump valve cycles, control pressure is applied to a diaphragm to counteract spring tension and open the dump valve. At the end of the cycle, the line from the controller to the diaphragm and the diaphragm dome are vented to atmosphere. If we assume that the two devices are connected by 12 ft of 3/8 tubing (0.0092 ft³) and the diaphragm dome is 0.04 ft³ (assuming 11-inch diameter, and 0.75 inches of travel) then the volume vented each dump is 0.049 ft³. At 35 psig and 60°F then this volume is 0.157 SCF/dump. At 5 dumps per hour this equates to 19 SCF/day (2% of a high-bleed device). The flow and pressure profile will look like:



Notice that the entire cycle takes something on the order of 0.3 seconds. This flow is made up of a period of sonic velocity (Reynolds Number 996,000) followed by a period of a significant fraction of sonic velocity (Reynolds Number ends up at 648,000 for 0.65 Mach), and finally a period of flow in a normal turbulent flow regime ending with a Reynolds Number of 10,000 just before the level control is closed. A measurement device would have to be able to go from offline to 294 MSCF/d within 5 ms, and be able to do a 100:1 turndown ratio. No meter ever made has that kind of latency or turndown ratio. Some meter technologies would give you numbers (most would never register), but none will give you measurement.

B. Gas Measurement Technologies

When I talked about "meter accuracy" above I always said "accuracy". "Accuracy" is an amazingly imprecise term that is never used by competent gas measurement professionals. The layman/advertising concept of "accuracy" is encompassed in the terms "repeatability" and "uncertainty" which have precise definitions that can be measured and used to compare the performance of a device relative to a standard or to another device.

"Repeatability" is a measure of a device's ability to report the same output for a given set of inputs. Many things can impact a device's repeatability. For example, turbine meters have the worst repeatability of all industrial gas measurement devices because gear lash is a random parameter that can change the speed of the turbine rotor by several percentage points independent of the magnitude of the change in measured input parameters. Acceptable repeatability occurs when the standard deviation of the sample data is within $\pm 0.05\%$ of the mean value.

"Uncertainty" is the "dead band" of the instruments. Each component of a gas-measurement station has a defined uncertainty, usually expressed in a range around the device's calibrated span. For example, a digital pressure transducer may have a stated uncertainty of $\pm 0.5\%$ which means that if the device has a calibrated span of 0-10,000 psig and reads 450 psig then the reading represents a value between 400 and 500 psig. Recalibrating the same device to 0-500 psig would change the meaning of 450 psig to 447.5-452.5 psig. Uncertainty is just that—you do not know where the actual number resides within the uncertainty range. A gas-measurement device is generally considered acceptable if the cumulative effect of each end-devices' uncertainty is less than $\pm 2.0\%$ (this is based on government requirements which were set before digital instruments, about 1% of the total uncertainty is uncertainty in manual chart integration, 0.5% is from using average temperatures). Electronic Flow Measurement (EFM) devices and digital temperature/pressure instruments make normal uncertainty less than 0.5% in most square-edged orifice (AGA 3) stations today.

Another important gas-measurement concept is "latency". Latency is a measure of the time lag between a change in flow and that change being reliably represented in the measurement device output. Every technology has some amount of latency. For example, a stopped turbine meter requires flow to overcome static friction before it starts spinning, and once it starts spinning it will tend to spool up to a high angular velocity before coming back down to report the actual flow rate. Consequently, turbine meters perform best in very steady flows—putting a turbine on the gas line to a separator dump valve would result in the meter not registering most dump events and over ranging on the few that it does register.

All gas measurement technologies are "inferential" technologies. This means that the equations infer a flow rate from some unrelated, but measurable, parameter. For example, Square Edged Orifice Measurement uses the Bernoulli Equation published by Daniel Bernoulli in 1738 to relate the pressure drop across a known flow restriction to a velocity, and then uses specific correlations developed for gas measurement to convert the velocity into a volume flow rate at standard conditions. The first assumption in Mr. Bernoulli's development of his famous equation is that the fluid is both incompressible and inviscid. Neither of these assumptions is literally true in a gas flow, but the industry has proven that both assumptions are close enough to being true to allow meaningful flow rates to be estimated. At commercial velocities, highly compressible natural gas does indeed act like an incompressible fluid unaffected by fluid friction over short distances. As velocity increases toward the speed of sound or decreases to result in a Reynolds Number under 4,000 the incompressible assumption becomes progressively less valid and the uncertainty in a measurement device increases dramatically.

1. Gas Analysis

Many states and the federal government have agreed that small wells (typically wells making less than 100 MCF/day) would be exempt from requirements for semi-annual analysis of the gas. This decision has not caused wholesale inaccuracies and I get the impression that all the stakeholders are satisfied with annual or even less frequent gas analysis.

For the Western Climate Initiative to re-introduce semi-annual analysis requirements and to propose quarterly analysis on small streams is not a reasonable imposition.

2. Square Edged Orifice Meters

The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. For a clean, well conditioned flow stream the uncertainty of the reported volume is on the order of 0.5-2%. Both uncertainty and repeatability are adversely affected by 2 phase flow, dirt, and changes in flow profile and in small-volume and/or intermittent service the uncertainty can exceed $\pm 25\%$.

These meters are the most common type of gas measurement in upstream gas operations. One of the reasons for their popularity is the extensive body of research that has gone into defining the meter configuration and operating limits. This research is documented in the series of reports collected into API 14.3 (also published as AGA 3).

The standards indicate that Square Edged Orifice measurement is only appropriate in meter tubes equal to or greater than 2.000 inches internal diameter (ID) and for Reynolds Numbers above 4,000. This means that the smallest volume that can be reliably measured with this technology at 35 psig is 5 SCFM (7.2 MSCF/day).

Latency in this technology is caused by the chaos in the flow as it moves to establish a pseudo-steady-state condition. I have evaluated carefullycontrolled flows at the Colorado Engineering Experiment Station (CEESI) during start-up using instruments that record pressures 100 times per second and have found that reaching repeatable flow in a Square Edged Orifice Meter can take as much as 5 minutes from a dead stop.

3. V-Cone Meters

The operating principle is to infer a flow rate from the differential pressure across a known restriction based on measured pressure and temperature. These meters are self-conditioning and tolerant of solids. The total uncertainty is on the order of 0.5-1%. Turndown is 10:1, and it is advertised to work down to Reynolds Numbers of 6,000 or greater.

This device has potential, but the smallest meter (1/2" ID) would register zero during pilot flow and would have a dP less than 7 inH₂O (0.25 psi)

while supplying gas to a 500,000 BTU/hr burner which would increase the uncertainty to several percent.

Latency of these meters is similar to Square Edged Orifice Meters.

4. Turbine Meters

The operating principle is to relate a rotor's angular velocity to a volume flow rate. Turbine meters assume reasonably steady flow with respect to time. Changes in rate take considerable time to steady out. Latency for a change to a flowing stream can be up to a minute, for a start/stop flow it can be many minutes.

Turbine meters rely on considerable mass to spin the rotors and they rarely provide adequate results in gas flows below 50 psig.

5. Coriolis Meters

The operating principle is that the momentum of a flowing fluid will vibrate a piping loop, and that the frequency of the vibration is a function of the mass flow rate and density of the fluid. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability. The MicroMotion division of Emerson has some fairly new instruments that can handle quite low flows, but the latency is similar to a turbine meter.

6. Ultrasonic Meters

The operating principle of Ultrasonic Meters is that there will be a Doppler Shift in the speed of sound as fluid moves away from a fixed sound-pickup point. The magnitude of this shift is a function of fluid density and fluid velocity. Low velocities and low pressures have a serious negative impact on uncertainty and repeatability.

7. Roots Rotary Meters

The operating principle of these positive displacement meters is to trap a fixed volume of gas within each revolution of a pair of lobes. Counting revolutions yields a volume.



This device is quite close to "measuring" gas volumes instead of "inferring" a volume from a tenuous mathematical relationship, but it is still counting revolutions instead of gas molecules.

Latency in Rotary Meters is very high due to having to start the rotors spinning again and leakage past the rotors before they start spinning.

8. Diaphragm Meters

The operating principle of these positive displacement meters is to fill a resilient chamber to line pressure, then that chamber is shifted to the demand side while a second chamber is filled. Each time the meter shifts chambers it records a pulse that represents a known volume.

The uncertainty, repeatability, and latency of these devices is excellent. Turndown ratio is on the order of 80:1. "Household quality" meters would handle the low flows, but materials of construction are generally inappropriate for field gas (e.g., they have considerable brass that is rapidly deteriorated by any H_2S in the flow; all of the Household meters have aluminum casings which have not stood up well to condensate service). "Industrial quality" meters are considerably more expensive and many of them still have inappropriate materials. A meter with no aluminum or "yellow metal" is difficult to find and is very expensive.

9. Exotic/Laboratory instruments

The volume of gas discussed in this application kept leading me to devices like "Thermal Dispersion Meters" (this meter has two probes, one is heated and one is a temperature sensor, the dT can be correlated to a mass flow rate, very long latency); and laboratory quality devices that are absolutely intolerant of free liquids and/or solids. None of these devices has a published standard for construction, installation, and operation and none has a reasonable chance of success.

10. Conclusion

In conclusion, the act of installing meters on the streams considered will provide a false sense of security and a net deterioration in the quality of data reported. Specifically:

- a) Engine fuel can be measured by dP inferential devices (either Square-Edged Orifice Meters or V-Cone meters), but the resulting metered volume will be very close to the theoretical data that is being collected today. Where the two numbers are significantly different I would expect that there is a measurement device error (such as an incorrect meter parameter or a backwards orifice plate) before I would expect the theoretical calculation is incorrect.
- b) No meter exists that can reliably measure both pilot flow and burner flow on a tank or separator heater if the burner is the only load on the system. If measuring these volumes becomes mandatory, then a diaphragm meter could be used to measure the pilot flow and either a Roots Meter or another diaphragm meter could be used for the burner flow. A fuel gas system with multiple engines and multiple burners could be metered with a V-Cone or Square-Edged orifice meter, but the burner volumes would only be able to be measured while the engine was consuming fuel—when the engine is not running, the burner is unlikely to register as an increment from zero.

The theoretical values for burners could be improved by putting a "valve open" clock on the supply line, which (in conjunction with manufacturer's data and Engineering analysis) would result in a better volume than attempting to meter the gas.

- c) Heater/Treaters, Dehy Reboilers, and Line heaters are reasonably constant loads that could be metered by several of the technologies above (the diaphragm meter would be preferred, but the small V-cone and the smallest Corriolis meter would work), but again the data would be of a similar magnitude of the data being reported today.
- d) No meter exists that can reliably measure the flow to a single dump valve or even a dozen dump valves off the same no-bleed controller. Even if a group of dump valves (three or more) were controlled off the same controller, the flow and pressure traverse would be similar to the one above and the meter would have to go from zero to 900 MCF/d in a few milliseconds then back to zero within about 1/3 second. It can't be done.

The diaphragm meter comes the closest, but it will tend to either be over ranged for most of the flow period or will fail to register a significant portion of the tail. I would guess that the total uncertainty would be on the order of 20-30%.

On the other hand, the flow to a continuous-bleed controller could be measured successfully with either a Roots meter or a diaphragm meter.

C. Wellsite Configurations

The reports from the Western Climate Initiative start with an assumption that there is something that can be reasonably termed a "standard" wellsite where fuel-gas measurement equipment can be "relatively easily" installed. This is patently false. The implication is that every site looks something like:



This layout brings gas from the wellbore tubing to a single separator, and then takes fuel gas off the separator outlet to supply both control requirements and fuel requirements. While there are wells that are configured like this, they are rare. A layout that would be equally as likely to occur would look like:



This layout did not suffer the expense of running a fuel gas line across the location to supply gas to the tank heater from the separator; it pulled that fuel stream from the casing valve and put a second fuel pot as a less expensive alternative to laying a line. Also, the compressor takes its fuel and control gas from an on-skid fuel-gas system. This is the normal configuration since

compressor-discharge gas is far better suited to both fuel gas and control gas applications than suction gas is.

This distributed fuel-gas supply scenario has evolved over the decades because the regulations in place at the time of site facilities-construction did not presume to tell operators how to build their sites.

III. Costs of Implementation

It is difficult to develop costs for a "typical" wellsite, "typical" automation system, or "typical" host/database modification because there is no such thing. There are companies within the WCI area of operation that don't have any automation or measurement on their wellsites today and use Excel spreadsheets to allocate sales volumes back to wells. There are companies with home-grown automation systems that have zero flexibility and cannot be retrofit for two additional volume calculations and would have to be discarded and replaced. There are companies with purchased systems that they do not have the license to modify. There are wellsites that will be trivial to retrofit. There are wellsites that will require laying new lines and replacing production equipment.

My approach to cost estimates is to try to address the wellsites, field automation equipment, and host/database systems that I've worked with at my clients operations over the years. I am certain that this technique will be representative of a large number of wellsites and a number of operators, but it will not be all encompassing because it is impossible to assess all of the permutations.

Accessing EIA data at

http://www.eia.doe.gov/pub/oil_gas/petrosystem/petrosysog.html and CAPP data at http://www.capp.ca/GetDoc.aspx?DocID=146286 for 2006 (the last year that has both US and Canadian well counts) I get the following counts of wells (after deducting 31,000 wells from California to account for Kern County):

	Gas	Oil	Total
New Mexico	36,202	15,456	51,658
California	3,692	16,197	19,889
Utah	5,259	2,574	7,833
Montana	6,207	4,199	10,406
BC	6,608	1,122	7,730
Manitoba	0	2,692	2,692
			100,208

For the economic analysis I'll use 100,000 wells.

A. RTU costs

Looking at the specifications on a number of RTU's, there are high-end RTU's like the Fisher FloBoss 107/107E that can accept multiple gasmeasurement inputs. These devices are not the norm for wellsite use. More common are units like the Kimray DACC 500 RTU that can only accept one flow calculation. At least 75% of the RTU's currently installed will need to be upgraded at a per-unit cost of \$4,000-5,000. Assuming that 25% of the locations do not need RTU replacement then the average for the wells is approximately \$3,500/site.

B. Host/Database costs

Host databases are very difficult to modify. Changing the Host requires that you: (1) have a place to put the new data; (2) change the data poling logic to pull the new data off the RTU to populate the new database fields; (3) add the new data to EFM editing programs; and (4) modify reporting systems to show the new data. I spent 12 years managing projects similar to this for Amoco and was involved when Amoco was making some significant changes to their host database. Amoco's changes were far less extensive than adding two measurement points that have to be reported to regulatory agencies and those changes cost \$15 million and took almost 2 years. If the average impacted user has 2,000 wells then for 100,000 wells in WCI you could expect to spend \$750 million.

C. Installation costs

After interviewing several operators and several roust-about service providers, modifying control and fuel gas systems to allow measurement and installing measurement equipment should be budgeted at 10 days of work per site. At \$1,200/day that is \$12,000/well labor. Jobs like this one are typically 60% materials (including the cost of a meter run of undecided technology) and 40% labor so total budgetary cost should be \$30,000/well—100,000 wells would cost \$3 billion.

This does not address the gas volume vented during the site blowdown and purge or the vented gas during semi-annual meter calibrations. To put that volume in perspective, for a small location without a compressor operating at 150 psig, the volume vented and later purged would be on the order of 2.5 MSCF—the same volume that would be vented in 131 days of operating a single no-bleed dump valve at 35 psig and 5 cycles/hour. The amount vented and purged during meter calibrations will depend on meter technology selected, but it is far from zero for any technology.

These costs also do not address the 2 weeks of lost production (call it 12 days at an average production rate of 100 MSCF/d) of something like 1,200 MSCF that was either deferred or more likely in competitive reservoirs was allowed to migrate to offset wells. At a \$5/MMBTU sales price the cost of this lost production is \$600 million across 100,000 wells.

D. Operating costs

Operating costs are the easiest to assess. A measurement tech can handle approximately 200 meter stations. The cost of a measurement tech with vehicle and benefits is \$150,000/year which works out to about \$750/meter/year or \$1,500/site/year.

IV. Conclusion

The idea that there would be any benefit to society from requiring gas measurement of control gas and fuel gas is patently false regardless of your position on the risk to society of gases being released to the atmosphere. A project to put this measurement in place would result in considerable vented gas, excessive capital expenditures, and excessive increases in operating costs. On the other hand the data from this expensive equipment would actually be less representative of the gases released than the current methods. In short, you would be implementing a very large cost to develop less precise data.