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MEASURING HYDROCARBON DEW POINT, THE ECONOMIC IMPACT

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Abstract

Identifying the major economic factors that drive the best practices for measuring the hydrocarbon dew point (HCDP) of natural gas fuel and implementing them can increase the profitability of operating a natural gas fired turbine. Online instrumentation provides reliable and accurate gas quality information upon which good operational decisions can be made. Implementing these best practices of measurement will result in increased profit and reduction of operational costs, unplanned shutdowns, turbine damage and potential liability for excessive emissions. Quantifiable costs, ROI, risks and savings associated with online HCDP measurements are discussed.

1 Introduction

Gas fired turbine operation has become an efficient method for generating power and has found a special niche in meeting peak demands in addition to making baseline power. The investment in these plants is significant, so they must be protected from damage. The ROI for installation and operation of these generator sets is realistic when the performance can be maintained over the life of each unit assuming the overhauls stay on schedule. But what if the unscheduled outages and overhauls become too frequent? Could fuel quality impact the profitability of gas turbine operations? Is the instrumentation, designed to monitor fuel quality, up to the challenge?

Turbine operators must consider the fuel requirements published by the manufacturer when contracting for natural gas. Failure to do so can significantly increase emissions, add to maintenance and operational costs, damage hot zone components and void warranties. In addition to these costs, there is an associated loss of revenue incurred during an unplanned shutdown for burner section overhaul. Finally, overcompensation for inadequate analysis techniques or an inferior choice of instrumentation may significantly add to the parasitic load of the operation.

"The gas turbine's major limitations are the life of the combustor cans, first-stage turbine nozzles, and first-stage turbine blades" Online availability of Combined Cycle Power Plants has declined as the result of using dry Low NO_X (DLN) combustors with the current natural gas fuel quality available.[1] These hot zones are vulnerable and unforgiving if the fuel quality is out of specification.

When using DLN combustors the perfect quality fuel is clean, dry methane. Particulates, acid gases, metals (i.e. Lead, Vanadium, Calcium, Magnesium, Sodium and Potassium) and other detrimental components are sometimes found in the gas. But when the fuel specification from every turbine manufacturer states **"Liquids: No Liquids allowed, gas must be superheated."** – and some even put it in boldface type – we must assume they have historical evidence that liquid in the fuel <u>will cause</u> damage and have specifically excluded all liquids in their fuel specifications.

The fuel gas is processed to remove water and heavy hydrocarbons to meet the specification in the contract/tariff between the buyer and seller. But ensuring delivery compliance with the contract/tariff is the buyer's responsibility. Therefore, *"Caveat emptor - Buyer Beware"* measuring both water and HCDP will identify the potential threat of any condensate/liquid in the gas that could cause turbine damage. These measurements become the basis for determining what processing, if any; will be required before the gas can be used as a suitable fuel for a Combustion Gas Turbine (CGT).

This paper addresses the measurement methods for determining HCDP and identifies the best practices to continuously ensure that fuel used for the CGT meets the manufacturer's specifications.

2 Fuel Quality Issues and Superheat Specification for Turbine Operations

In addition to limiting impurities in the gas, many turbine manufacturers recommend the superheat of 28°C (50°F) above the dew point of water or hydrocarbons, whichever is higher. All CGT manufacturers specify a superheat sufficient to prevent liquid condensation as the pressure is reduced from pipeline pressure to the turbine inlet pressure.

3 Hydrocarbon Dew Point

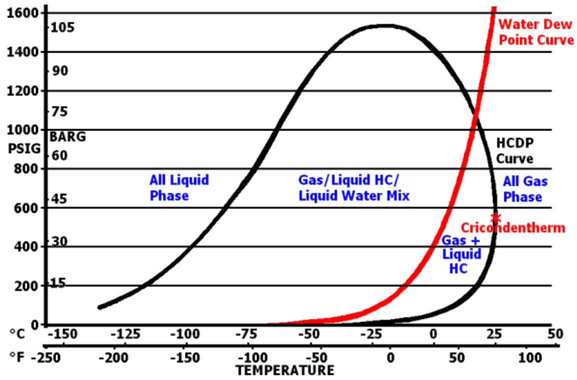

Figure 1: A typical natural gas phase envelope is shown identifying the phase of a pre-processed gas in the various pressure/temperature domains

Hydrocarbon dew point (HCDP), is the temperature where liquid hydrocarbons begin to condense at a given pressure. From a practical perspective the concern is at what temperature do these condensates become a problem for either moving the gas or using it. This can be seen on a mirrored surface as a formation of hydrocarbon liquid droplets as the mirror is gradually cooled at the rate of 0.5°C/min. This measurement is directly affected by pressure, temperature and the constituents of the gas in the sample. As pressure and temperature are changed for a given gas sample, the HCDP follows a curve that is called the phase envelope of that gas (see Fig. 1).

There is no direct relationship between the hydrocarbon phase envelope and the water dew point curves as they are driven by totally separate gas conditions. Every field or processor's gas will have a different phase envelope shape that describes their gas. The water dew point curve will be the same shape but may move with respect to the 'X' axis determined by dehydration processes upstream. The maximum temperature at which a hydrocarbon phase change occurs is called the Cricondentherm from "Critical condensation therm (heat)".

3.1 Phase Envelope

Since natural gas is a mixture of several compounds, it has a phase behavior driven not only by the pressure and temperature for each individual compound but also their interactions. The overall composition can be shown with a "phase envelope" diagram where the pressure is shown as the 'Y' axis and the temperature as the 'X' axis. As the various points are plotted to show the state of the gas, a retrograde curve develops with several points of interest to processors, pipeline operators, and wholesale gas customers.

The information from a phase envelope diagram for delivered gas is very valuable in many respects. It tells at what temperature the gas can safely sampled to properly determine heat content per API Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer. It can tell us what might happen if the pressure is reduced or even indicate over time the health of a supplier's processing unit.

3.2 The Pressure Reduction Problem

Gas fired turbine generators are not fired at transmission gas pressures. Proper superheat is critical because the Joule-Thompson (JT) coefficient has a big impact on the phase of the fuel. When natural gas is delivered, pipeline pressure must be reduced to be used to fire the turbine. This let-down can be as much as 7.24 MPa (1050 psi), i.e. from 8.62 MPa (1250 psig) to 1.38 MPa (200 psig). Expanding Natural Gas produces a JT cooling effect of ~3.9°C

(~7°F) per 0.689 MPa (100 psi) drop. At this extreme case the total drop would be~3.9°C X 7.24/0.689 = ~41°C (~73.8°F). Even in this extreme illustration of supply pressure, if the HCDP is -9.4°C (15°F) and the gas temperature is less than 31.6°C (88.8°F), there will be some condensate that could drop out during the pressure let-down.

This risk is present even though, as in this illustration, the 28°C (50°F) superheat specification is met. The heavier hydrocarbons present (mostly liquids at this point) will have a longer burn time. The non-optimal combustion produces a higher heat that will exceed the turbine hot section design as well as generating increased emissions of un-burnt HC and increased concentration of NO_X, CO, CO_2 in flue gas. These emissions are of interest to air quality regulators and as a consequence there is an additional risk of fines.

Accurate measurement of the water dew point (WDP) and the HCDP will allow operators to control the energy requirement for achieving the proper superheat temperature.

3.3 Suppose Liquids Condense

Once condensates have formed, they often cannot be heated quickly enough to revaporize and prevent turbine damage. Liquid phase components require much more energy to force them to evaporate. Since the flow is high and the distances and dwell time in a heating zone would be very limited, it is much better to ensure the gas remains totally gaseous.

Should condensates form, coalescing filters and knock-out pots can help but they must be maintained and the liquid must be continually removed for them to work properly. If not, damage will result.

3.4 Flashback

Today's DLN units premix fuel and air prior to ignition, and if liquid hydrocarbons condense in the combustors, serious damage will occur. The fuel is supplied to all the combustors using a ring-shaped manifold. If liquids form and collect in this ring, the lower combustors on the turbine will receive two-phase fuel. Since the fuel-air mix is disturbed, incomplete combustion occurs leaving behind some excess liquids in an area that is not suited for high heat or pressure. When these liquids ignite, this 'flashback' creates a pressure wave that propagates through the turbine. If allowed to continue, this will result in turbine engine failure.

4 Costs/Risk of Incorrect HCDP Information

The costs or risks of not having accurate HCDP information fall into several areas. One of the first problems to appear when burning gas with excessive HCDP is that NO_X emissions increase dramatically risking stiff penalties. Another cost is in the damage done to equipment. Finally, there are potentially additional parasitic loads which cut into profits as well.

4.1 Emission Penalties

"The majority of the NO_X produced in the combustion chamber is called 'thermal NO_X'. It is produced by a series of chemical reactions between the nitrogen (N_2) and the oxygen (O_2) in the air that occur at the elevated temperatures and pressures in gas turbine combustors. The reaction rates are highly temperature dependent, and the NO_X production rate becomes significant above flame temperatures of about 3300°F (1815°C)."[2]

The EPA is very strict on emissions and the requirements are continuing to tighten. Fines of several hundred thousand dollars to tens of millions have been levied against power companies because of excessive emissions.

As the fuel gas content of heavier hydrocarbons increases in a DLN turbine, the NO_X emissions will significantly increase.

In short, good quality gas is the solution and if the contract/tariff with the gas supplier was written well, the task is simply to ensure compliance. But that tariff should include how the measurement of HCDP and WDP will be made. This will determine in large part, how much variance the actual specification can be without incurring litigation over non-compliance. If the method for measuring this critical parameter has inherent accuracy limits, there is no recourse until the contract comes up for renewal.

4.2 Burner/Combustor Damage

Burner damage is also a serious concern for users. High HCDP gas burned over time will create higher burner temperatures which will eventually pit and deform the burner cans and nozzles. Eventually the effect will translate to the hot zone turbine blades and begin to erode the blade tips. This degrades efficiency and the turbine loses power. Fuel costs begin to climb and the profit margins shrink. Gas turbine burner design and materials can handle some variance in the fuel specification but they are not designed to handle any liquids in the fuel.

Every turbine design brings with it a strict fuel specification. For gas fired CGTs, this includes fuel with a low HCDP and low water content. The superheat specification is meant to handle the pressure drops of fuel quality specified by the manufacturer. Once the turbine is selected, the burden of fuel compliance is on the turbine operator. If the fuel burned is out of specification, the damage caused becomes the operator's responsibility and this repair just for the turbine burner section can be upwards of \$2.5M[3] per occurrence.

4.3 Flashback Damage

When flashback is detected, it requires immediate action so the shock waves do not reach critical stress on the turbine rendering it unsafe for further operation. Flashback is often audible to personnel in close proximity to the CGT and the sound ranges from a chugging to a rumbling sound. It is a symptom that should never be ignored. The immediate remedy is to throttle back on the turbine seriously reducing efficiency or shut it down completely.

Below are some illustrations of the damage caused by high HCDP and flashback events. The damage in Figure 4 and repair would be many times that of the burner damage above.

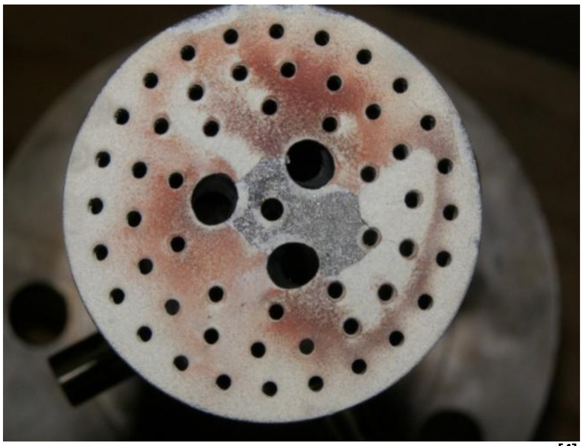

Figure 2: **Burnt Burner Tip From DLN Combustor[4]**

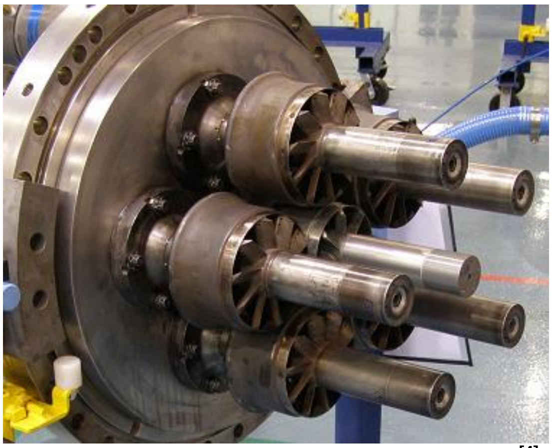

Figure 3: End Cover assembly prior to repair[4]

Figure 4: **DLE Combustor showing damage due to flashback[2]**

Figure 5: Fuel nozzle damage due to flashback[2]

4.4 Higher Parasitic Costs

Figure 6 illustrates a case of gas at 6.9 MPa (1000 psig) with a temperature of 21.1°C (70°F) is used to fuel a gas turbine. When the pressure is reduced to introduce it into the burner section, the JT effect is shown by the line AB. The constituents of the gas produce a phase envelope that will be intersected by this pressure/temperature drop just below the 4.1KPa (600 psig) pressure. The HCDP is the only curve that is intersected in this case; in order to avoid the formation of condensate, the fuel must be heated. The cricondentherm dew point is found at 4.4°C (~40°F). Adding 27.8°C (50°F) of superheat which is required by the manufacturer, calls for the fuel to be heated to ~32.2°C (~90°F) before entering the pressure reduction section of the fuel system.

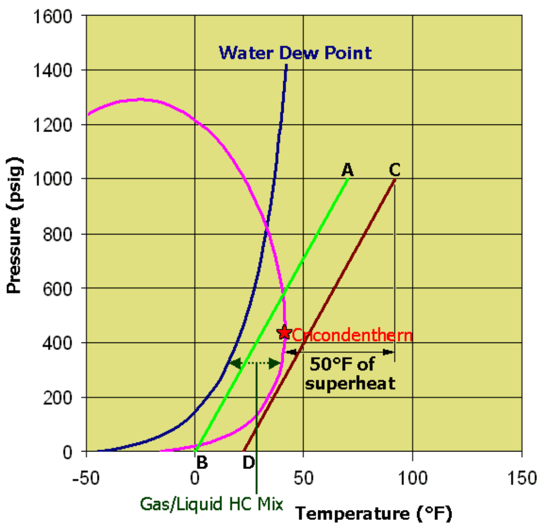

Figure 6: Practical function of superheat to prevent condensate formation

This superheat significantly reduces the risk of condensate forming in the fuel system (see line CD) with the same cooling effect slope. But if the hydrocarbon or water dew points in the fuel are unknown or incorrect, the control of the superheat will be incorrect, risking either turbine damage or adding to the parasitic load of the operation. Both will add significant costs. One CGT manufacturer recommends that the gas temperature be the basis of determining the superheat value.

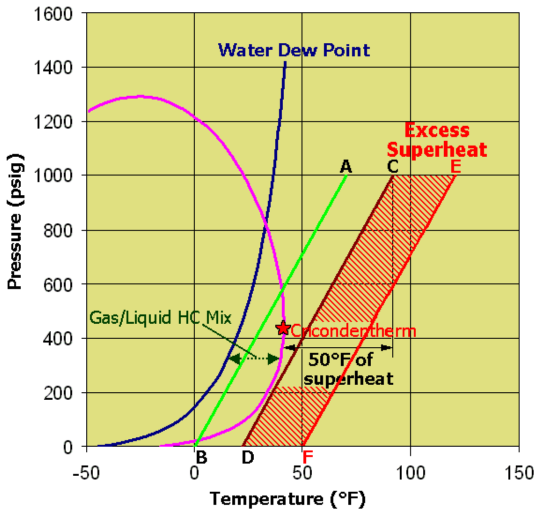

Figure 7: Graph of gas temperature-based superheat

An example of this practice is shown in Figure 7 where the gas temperature supplied is ~21.1°C (~70°F) and the resulting superheat temperature is ~48.9°C (120°F). This illustrates an excess parasitic load to heat the fuel gas the extra 16.7°C (30°F) simply because the dew points are not measured accurately. “For a GE Frame 7 gas turbine, 27.8°C (50°F) of superheat amounts to about 740 kW, which means energy cost can be as high as $324,120 per year”[5] (in 2001 dollars). If that fuel is to be heated 44.4°C (80°F) over the CHDP as the result of a temperature based operation, that number could be in excess of $650K/year.

5 How is HCDP Measured?

There are three primary methods used in North America - Manual Dew Point Analysis, Gas Chromatography (GC) with Equations of State (EOS) and Automatic Dew Point Analysis.

5.1 Manual Optical Method

The Bureau of Mines device has been used since the 1930s to provide manual dew point measurements and is generally considered the de facto standard in the industry. This device is used for “spot checking” the dew point of a sample as extracted from a tap on the pipeline, from any location in a gas processing facility or point of use. It allows a trained operator to detect the dew point visually and interpret that image as a HCDP, a WDP or a contaminated dew point. One measurement performed in accordance with ASTM D 1142 Standard Test Method for Water Vapor Content of Gaseous Fuels by Measurement of Dew Point Temperature can take a full hour. On-the-job training, including viewing hundreds of images under different conditions, is required to be able to operate this instrument properly. Since there is significant subjectivity in the interpretation of the images, there will usually be some bias in the readings.

5.2 Equations of State from GC Data

GC analysis is employed to determine the BTU content of the gas sampled. With the respect to HCDP, equations of state have been developed to predict the HCDP of the gas sample. “Hydrocarbon dew point is mainly influenced by C_7 and above hydrocarbons. … Therefore, the traditional “C_6 plus” analysis provides insufficient data for a valid hydrocarbon dew point calculation."[6] "Using a C_6+ characterization instead of a full characterization containing all known components of the gas was found to change the computed dew point by as much as 70°F, and invariably led to under-prediction of the dew point. … Based on comparisons to date, however, the C_9+ characterization most often appears to predict measured dew points to within ±25°F."[7] (13.9°C)

"Small quantities of heavy hydrocarbons above C_6 raise the dew point significantly. Using a standard analysis can result in an artificially low dew point determination… Extended Gas Analysis to C_{14} … checks for the presence of the heavy hydrocarbons and quantifies their amounts to the level of C_{14}. … It is, however, the only type of (EOS) analysis that will result in an accurate dew point determination. … An analysis procedure for C_1 through C_{14} is described in GPA 2286-95."[8]

GCs designed to meet these extended analysis specifications are laboratory instruments and are costly for normal power plant operation. C_6+ GCs are most commonly used in the field to check the BTU of the gas – and they are effective for that purpose. There are a few C_9+ analyzers used on pipeline gas and in end-user installations. These are primarily used to provide HCDP in addition to the heat content of the gas. Many users are applying equations of state to provide a calculated HCDP. But this needs a closer look.

Table 1 below shows how equations of state require information that cannot be provided by available field GCs. As indicated from this extended analysis, even using a C_9+ GC with a GPA recommended 60-30-10 extrapolation split, the HCDP value is underestimated by 16°C (28.8°F). Adding the JT cooling effect of reducing the pressure to 1379 KPa (200 psig) pushes the superheat requirement by another 7.8°C (14°F) to a total of over 32.2°C (58°F). If 27.8°C (50°F) of superheat is estimated to cost $650K /yr today, adding another 32.2°C (58°F) of heat to the fuel would significantly increase that amount. Turbine damage due to the additional condensates is the alternate risk.

The extensive study by Southwest Research Institute (SwRI) has reinforced the fact that the point at which temperature and pressure allow microdroplets to first be seen on a mirror defines this point of critical concern. This closely approximates the description referenced in ASTM D1142. That work is published and available from their web site.

Table 1: EOS Data from GC Analysis to Determine HCDP

EOS Analysis Extent		C_6+	C_6+ with 60/30/10 split	C_9+	C_9+ with 60/30/10 split	C_{14}	C_{14}-C_6+
HCDP @ Cricondentherm	°C	-28.0	-12.9	3.7	13.8	29.8	57.8
HCDP @ Cricondentherm	°F	-18.4	8.7	38.6	56.9	85.7	104.1

5.3 Automatic Optical Method

Automatic HCDP Analyzers have been in commercial use for over twenty-five years and independent laboratory testing has shown them to have very good accuracies to ±1°F when compared with the Bureau of Mines Manual Dew Point method. They also provide the user with updated information every five minutes. An optical detector is chilled until a layer of condensate forms on that surface. Measuring the detector temperature when that occurs gives the HCDP temperature. Automatic Dew Point Analyzers are not influenced by individual operators and include the entire spectrum of species in their analysis. They are available in field installable units that can be mounted very near the sample tap, providing a fast response to any change in the properties of the gas.

5.4 How Do These Three Methods Compare

The three methods currently used by nearly all companies in North America are compared in this application as Table 2 below indicates.

Table 2: HCDP Measurement Method Comparison

Method	Accuracy	On-line	Measured/ Calculated	Operator Bias	Operator Training	Installed Cost ~$K	Maint./Ops. Cost ~$K/Yr
Manual Optical	Excellent	No	Measured	Yes	High	10	10
EOS from Field GC	Poor	Yes	Calculated	No*	High	75	7
Automatic Optical	Excellent	Yes	Measured	None	Low	60	<1

If a parameter can be measured or inferred by calculation, the preference is always an actual measurement. The historical performance track record of the Automatic Optical HCDP Analyzer is proven: direct measurement provides information 24/7; it is reliable, accurate and requires little maintenance. Installation in challenging climates can be achieved using customized instrument/sample systems for optimal performance. *Operator bias for EOS method can be seen in the concentrations used for extrapolation beyond the "+" the CG provides (e.g. when using a C_6+ GC the C_6 through $C_{n>6}$ values chosen) have a dramatic impact on the calculated value.

6 Recommended Best Practices

The important practices and analyzer system design required to produce accurate HCDP and WDP measurements include the following:

1. Proper sampling – Always follow manufacturers' recommended sampling techniques. This sample must be drawn off through heat traced tubing from the point of extraction through to the analyzer. This is a critical issue since all surfaces contacting the sample gas must be maintained at a temperature higher than any dew point to assure accuracy. Fast or speed loops should be used for maximum speed of response.

2. Reliable Detection Method - A reliable detector is a given for all instruments. Without the right sensor, discriminating a true HCDP has been tricky because the appearance of its condensate is often confused with other condensables. Independent laboratory reports like those produced by SwRI and GERG can be a good source for reliable instruments with HCDP accuracies in the range of ±0.5°C (±0.9°F).

3. Close Proximity to Pipeline Sample Point - A unit that can be installed near the sample tap will produce faster information updates due to less sample transport time.

4. Interrupting Flow of the Sample during the Measurement - A sample that is allowed to flow across a detector continuously creates a disproportionate deposit of the heavier hydrocarbons on the optical surface. These heavier molecules are the first to condense as the temperature is decreased and will always bias the readings. Automatically halting the sample flow during the measurement cycle will eliminate this bias producing more accurate readings.

5. Measuring at the Cricondentherm Pressure - This is a very significant point on the curve. When pressure is reduced from the pipeline pressure the JT effect will be in play and impact the phase of the fuel being delivered to the turbine. All across North America this cricondentherm falls into a fraction of the overall pressure range of Natural gas samples at roughly 2.4-3.4MPa (350-500 psig). When the curves are examined, this section of the curve is nearly vertical. Pressure changes within this band will have very little impact on the accuracy or uncertainty of the measurement.

6. Heating the optical surface between measurements - This heating cycle needs to be long enough to eliminate the condensate residue and prepare the sensor for the next measurement. Without sensor heating, the total cycle time can be three to five times greater than the heated one and result in less reliability of the measurement.

7. Small internal volume - When the volume of sample in the measuring chamber is reduced, it will speed the measurement, producing data more frequently.

8. Frequent Measurement - Measurements every 5-10 minutes are available and provide for better response to changes in the gas conditions. This also allows control functions to be implemented in a more timely fashion.

7 Conclusions

Variations in the supply of the gas will occur. Using good instrumentation will prevent turbine damage and increase reliability of the plant to produce power. Fully featured automatic HCDP analyzers will produce the best results and will often have a ROI in just a few months of operation that justifies their installation. Should an upset in the gas supply occur, these analyzers will pay for themselves on the first occurrence by alerting operations in time to protect the turbine.

Good fuel quality management benefits from trustworthy HCDP monitoring. Fuel cost of operating a turbine is a major portion of the budget and verifying the quality of the fuel results in more profit and less vulnerability to CGT damage. Keep in mind that the gas in the pipeline rarely changes characteristics abruptly and watching the dew point trend can predict the need to change controls or shut in a supplier in a timely manner if the gas falls out of the tariff specification. Maintaining good historical records will also be of value should an analyzer go down. The past seasonal performance will generally be reliable to use for short periods especially if a GC is also on line measuring the heat content of the gas. Spare parts of critical items should be kept in stock. These items are available from the instrument vendor.

Operating the measurement appropriate analyzers will provide for fewer unplanned and unbudgeted outages, enhance deliverability to your customer, add turbine life, and lower operating costs thereby increasing profit.

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