JISKOOT™ QUALITY SYSTEMS

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How accurate is your receiving metering system?

by Mark. A. Jiskoot, Reprinted from Hydrocarbon Processing

Errors in terminal receipts due to poor sampling designs and procedures can result in huge losses.

When receiving crude shipments via tanker, there is some doubt on the quantity of product unloaded. Many errors can be attributed to discrepancies in sampling and metering results. Oil quality measurement methods are under continual review. How much water are you actually purchasing in the latest receipt? An answer is determined by what methods are used to get product densities and the accuracy of laboratory analysis. Should physical sampling methods be replaced with online devices? These are just a few of the issues that refiners must consider as they try to improve the operation of their terminal metering systems.

Loss reduction-what does it mean?

Oil companies established 'loss control groups' to minimise losses that they were making in the total product lifecycle.

Many papers showed how losses could be assigned to leakage, evaporation, process or measurement. When all physical losses are accounted for, then we are left with measurement – quantity and quality. These two are totally dependent, but quantity is always perceived as more important to the negotiation than quality. Think of a ton of gold, a ton of lead, a ton of air. None of these describe more than a quantity and a perception of value.

Consider a typical investment in measurement, a million dollars may buy a measurement system. When we consider the overall measurement accuracy of the total value (quantity and quality of oil), we can achieve volume to ± 0.5% and we achieve water content to ±0.05% (per 1% water). Given that the average water contents are in the range of 0-5% v/v, then the meter contributes 0.5% and the quality measurement 0.25% to our overall uncertainty (Fig 1). These numbers should suggest that the value in 'loss control' of the quality sampling system is half as important as the metering unit.

In a combined measurement system, when was the sampling system close to half the value of the metering unit (Fig 2)? Little attention is paid to the importance of sampling, when it can be so significant to the loss balance. Why is the sampling unit handled as a low cost commodity?
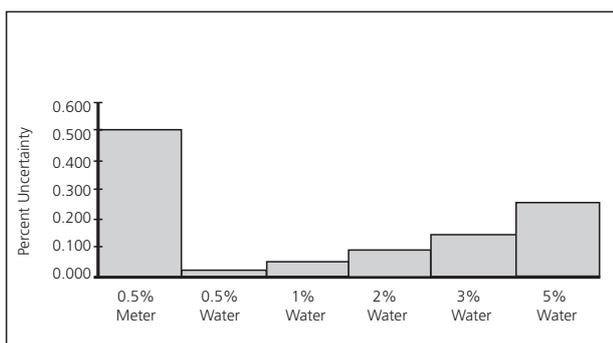

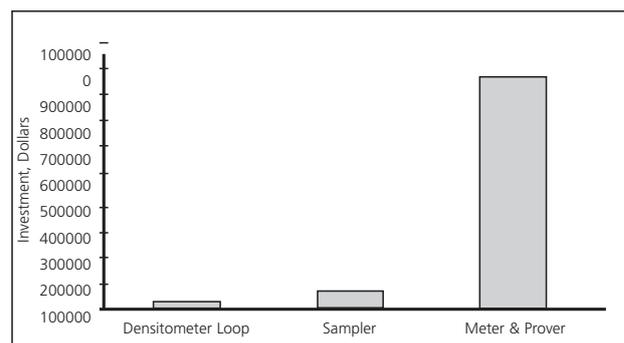Fig 1. Effects of water content on error management

Fig 2. Investment on metering system's individual components

Table 1.

Net Standard Volume (NSV) losses for load and receipt terminals

Year	NSV Loss
1989	-0.34 %
1990	-0.32 %
1991	-0.30 %
1992	-0.30 %
1993	-0.29 %
1994	-0.25 %
1995	-0.22 %

Table 2.

Leading losses by crude type

Crude Type	Loss
Arab Extra Light	-0.11 %
Arab Light	-0.26 %
Arab Medium	-0.27 %
Arab Heavy	-0.34 %

Table 3.

Qualifying Levels for samplers

Water %	ISO	API by Tank	API by Meter
0.5	0.050	0.130	0.090
1.0	0.050	0.150	0.110
1.5	0.075	0.160	0.120
2.0	0.10	0.170	0.130
3.0	0.150	0.190	0.150
5.0	0.250	0.190	0.190

This approach has led to a valuable and ongoing upgrade market for fiscal samplers. But it is hard to believe that the engineers involved in purchasing measurement systems do not save the trouble or additional expense by either separating the sampling from the metering package or alternatively taking the trouble to:

• Provide an extremely detailed specification

• Require a performance guarantee on *all parts* of the measurement system.

There's no water in my oil

Many oil suppliers prefer to state that their production is dry or 'trace'. Often, the lighter the crude the drier the potential shipments become, but this is only true if: the oil is separated out in the process, the tanks well sealed and/or the water drawn from the tanks prior to loading. However, ships unloading oil from these 'dry suppliers' always seem to have similar TOV's but higher water contents.

The latest published PM-L-4A committee results (for year ending 1995) show improvements in loss reduction (Table 1). This has been linked directly to improved measurement standards and practices at both load and receipt terminals.

While the industry average now appears to be –0.22%, it is apparent that the quoted figures for local crudes still exceed these losses. The total for local crudes still show a loss of –0.265%, the worst being Arab Heavy at –0.34% (Table 2). What is also interesting about the figures is that they clearly bear out the relationship between API and measurement accuracy.

Given a uniform style and sampling methodology; these figures are predictable. The Extra Light crude is probably shipped drier than the other crudes because water is easily and quickly separated. The Heavy crude is likely to have higher background water levels from the process.

Proving systems

Proving a system is paramount to acceptability. But what standard should you use? Which one is the best? The API

released a new 8.2 standard in 1995. Unfortunately, this reduced the qualifying level for samplers from a then 0.05% to 0.13%. This made it far easier to certify equipment to this standard (Table 3). Unfortunately the API voted the IP input at ballot as "technically non-persuasive". The IP position was, and remains, that all proving work submitted to the IP exceeds the test data that the API then had to hand, and indicates that the ISO standard was achievable repeatably. The only fundamental difference between the data sources was that the European test data was totally based upon what are known as "fast loop systems", whereas the U.S data was without exception based on inline systems. The type of fast loop systems now used in Europe are far different than their forebears and the types illustrated within the current API.

The new qualifying level may be fine for many vendors and users who can now easily meet the criteria, but it reduces the overall measurement quality that is attainable in this business. It defames efforts and investments of those that have worked hard to achieve the best standards. It is interesting to note, that the proving tolerances are ±, as are those for metering. However, the PML-4 (Table 1) shows an average loss. Also, the proving data shows that 90% of systems pass their test within the negative tolerance band, which implicitly suggests that water is likely to be undermeasured.

Many systems have been proven and continue to be proved to the tighter levels specified in the ISO 3171 and IP 6.2 and this should remain the standard of choice.

Even once the system is proven under worst case conditions to sample accurately, it is imperative that on a load-by-load basis all the steps in the sampling procedure have been properly followed and documented. Too often, the operator still goes to the field and finding nothing in the sample can, fills it from the nearest valve. Unless there is a hard copy logging system on the sampling system, there is no proof that the system was indeed operational and that the sample was correctly taken. This is one of the great weaknesses of an online measurement system – there is no physical method to check that the system is working on a load-by-load basis and there is no recourse if it fails.

Our sampling methods are accepted-why change?

In the fuel oil "bunkers" market, there is a "white list" which provides factors for buyers to consider what the average water content is compared to what it is claimed to be. This is an uncertainty factor and this adjustment is applied to the offer price. It makes sound economic sense when considering a purchase to factor uncertainty into the equation. What is metering about if not uncertainty? If the trader (buyer) is to calculate the income he can get on buying oil, the buyer needs both the quality and quantity to value it. The buyer then applies an uncertainty factor to those receipts to calculate price. Less uncertainty means a higher price, more money in the sellers pocket. It is in the interests of both parties to know the true value of the goods. If your trading partners aren't asking you to improve your measurement, it probably means that they've figured out that they getting more than they paying for.

Why not use online devices?

Considerable work is being done in the on-line measurement of both singlephase and multiphase flows. This technology is maturing fast, but there are many pitfalls to be found in correctly applying it.

Often, unsubstantiated claims for it's use are found in literature. For example, one manufacturer's literature stated for "marine loading and offloading" duty, Insert the device 5.8 in. into the flow. All the sampling standards require that the sample offtake position should be D/3 and 0.1D below centerline. So what size transportation pipelines do you have? Three times a 5.8 in. insertion length gives us a maximum of 17.4 in. Nowhere in this same literature does it state that the pipeline must be well mixed. Common sense tells us that mixing is suited for fiscal sampling and must be applied.

The third issue is in reference to the performance of any of the units that use as the final reference Dielectric constant (and this includes all microwave techniques). They fundamentally require stable salinity and density, and no water slugs. These are unlikely at many load ports.

So when considering online devices, Remember: It is an immature technology and one that must be very carefully applied, if at all. Where an online device is used, the result is just that, dynamic and online, when the oil has passed, the ship is gone, no traceability remains. Any spurious results or calibration errors are both undetectable and irreversible. However, where a physical sampling methodology is used, it is immediately obvious if the system performance is recorded that a flow proportional sample is or is not being achieved. With a physical sampling system, the operator has the ability to fall back to alternative methods (Fig 3).

It will be quite some time before on-line devices move from information gathering and allocation measurement to true fiscal and legal duty. Whatever methodology is used, the system must be verifiable on an ongoing basis and proven for a range of process conditions. How do you prove an online device?
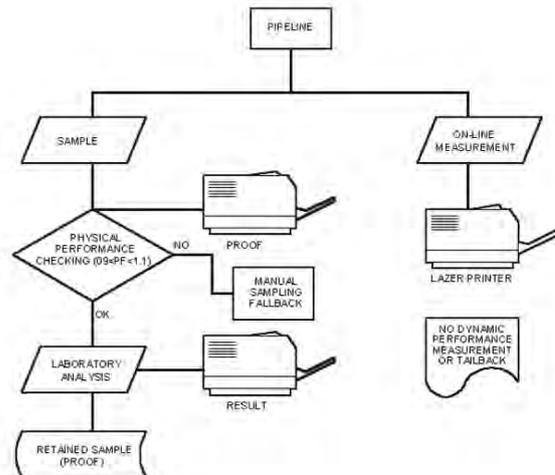

Fig 3. Schematic differences between online and sampled measurement systems

How can we improve accuracy?

Six steps are required for adequate sampling:

1. *Installation position relative to the custody transfer position*
2. *Homogeneity of pipeline contents*
3. *Extraction of a flow proportional and representative sample*
4. *Sample handling and mixing*
5. *Laboratory analysis*
6. *Prove all of the above and show ongoing performance.*

In several areas, there is still insufficient effort being made, particularly given that reliable and well proven technology is available to address accurate sampling. *Installation position relative to the custody transfer position* is an awareness still frequently overlooked.

Homogeneity of pipeline contents. Mixing is still a poorly understood and a mis-engineered area. Many engineers either are not realizing or are unwilling to accept the requirements. Even those now seeking to use on-line analysis technology, frequently fail to accept that a well-mixed pipeline is a pre-requisite to taking an analysis at a single point on the cross section.

The most misunderstood area in pipeline mixing is rangeability. Static mixers are frequently applied beyond their
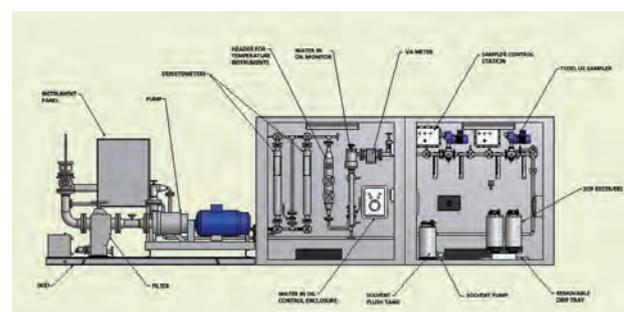

Fig 4. Schematic of a measurement/sampling unit

real design limits. The mistaken belief that if the static mixers mix properly at the high flowrates, "it doesn't matter if they don't mix so well at the low rates". Static mixers only have a turndown of 4;1; they are not suited to loading or discharge operations subject to a rangeability of over 30:1.

Extraction of a flow proportional and representative sample
Maintaining representivity is still not applied correctly. The performance factor of a sampling device must be in the range 0.9 to 1.1 not only for the whole of each batch but at any point in the batch.

Sample handling and mixing
Sample receiver selection and mixing is not universally applied. Not all users recognise that the whole result of the sampling operation depends on every step in equal measure. Sample receivers and laboratory mixing continue to be a problem although the API 8.3 has set down some improved criteria. Analysed data on density from sampling systems show the effect of RVP, mixing and of the receiver types on density results.

After conducting a number of tests on sealed receiver/mixer combinations, we discovered that despite being sealed, the density result will vary with the mixing time. Lionel Downer, a loss control man from BP, who originated the IP200 equations, commented: "there is no such thing as a retained density sample". The needs of sample handling and density are mutually exclusive – a sample well mixed for water will provide a poor density result. For this reason, density must always be analysed before water.

Laboratory analysis
Another major failing is laboratory analysis. The internationally accepted standard for water content analysis is the Karl Fischer method. This method is almost universally used but for a few countries. In general, the Karl Fischer method will reveal more water than either distillation or centrifuge. It is evident that the Karl Fischer analysis is more likely to be used where people are interested in revealing water and centrifuge method is used where they are not.

Prove all of the above and show ongoing performance
Many people are still installing fiscal samplers without automatic performance monitoring. Without performance monitoring, no fallback methods are available.

More on sampling

Shipboard samplers are more accurate than tank samples; inline samplers are more accurate than shipboard samplers. Finally, fast-loop samplers are more accurate than in line samplers. The best sampling system available is a fast-loop based unit. Consistent and repeatable provings are exhibited

by correctly designed fast-loop units within the 0.05% allowance of the ISO standard, whereas many inline systems will only prove repeatably to the wider bands allowed by the revised API standards.

A fast-loop system provides the best path to the future. Many metering systems now use live densitomenter inputs and these are normally loop-based instruments. Because a loop based instrument is easier to maintain, why do we see installations using a loop for a densitometer and an in line probe (Figure 4).

Of course as online analysis methods become more accurate and robust, they can easily and best be accommodated as part of a fast-loop system.

Three years of data comparing in line samplers with shipboard samplers show a consistent water difference of –0.03%. Three years of proving, show that fast-loop systems proving to the ISO 3171 at 0.05% repeatably, while in line systems prove more easily to the lower API tolerance of 0.13%. The data show that most laboratories still do not mix their samples properly and get variable density results.

The author

Mark Jiskoot is the managing director of Jiskoot Limited, a business supplying specialist engineering solutions to the oil, gas and petrochemical industries. Mr Jiskoot became managing director in 1991 after a period as sales director and a five year secondment to the U.S where he established the company's Houston operation. Mr Jiskoot is an internationally acknowledged expert in the field of liquid hydrocarbon sampling. He graduated from Imperial College in 1980 and since that time has been the pivotal point for the development of international sampling procedures. In addition to his work with the major international sampling standards boards of the API and IP, he sits as the UK representative for ISO 3171 and ISO 3170. Mr Jiskoot is also heavily involved in committees addressing the application of these standards for specific industries, such as IBIA, and is a regional councillor for the CBI. He has presented technical papers at international conferences and authored several articles. Mr Jiskoot has recently been employed as a consultant for Shell as a sampling specialist and as managing director; he has advised and supported most of the major oil companies.

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