RPSEA

Improvements to Deepwater Subsea Measurement – Consolidated Final Report

07121-1301.FINAL

Improvements to Deepwater Subsea Measurement

07121-1301

December 30, 2011

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Abstract

The U.S. Department of Energy, through its Research Partnership to Secure Energy for America (RPSEA) initiative, working in concert with a consortium of seven deepwater operators, has sponsored a Joint Industry Project (JIP) to address perceived gaps in measurement of flow in deepwater. The project actually consisted of six individual sub-projects, each addressing one of the identified gaps: Deepwater Subsea Sampling, ROV-Conveyed Measurement, HPHT Sensor Development, Virtual Flow Meter Evaluation, Meter Fouling Effects, and Measurement Uncertainty Tool Development.

This report consists of seven individual final reports. These seven include the final reports for each of the six technical areas addressed in these sub-projects, plus an overview report of the entire project.

Prepared by:	Approved by:
Winsor Letton, Ph.D. (LHG)	Winsor Letton, III Date: December 30, 2011

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RPSEA

Improvements to Deepwater Subsea Measurement

Final Report

07121-1301-Task7.FINAL

Project 07121-1301

September 29, 2011

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Abstract

The U.S. Department of Energy, through its Research Partnership to Secure Energy for America (RPSEA) initiative, working in concert with a consortium of seven deepwater operators, has sponsored a Joint Industry Project (JIP) to address perceived gaps in measurement of flow in deepwater. The project actually consisted of six individual sub-projects, each addressing one of the identified gaps: Deepwater Subsea Sampling, ROV-Conveyed Measurement, HPHT Sensor Development, Virtual Flow Meter Evaluation, Meter Fouling Effects, and Measurement Uncertainty Tool Development.

This report briefly summarizes the efforts of each of these sub-projects (tasks), as well as other salient features of the project such as financial performance and technology transfer.

Prepared by:	Approved by:
Winsor Letton (LHG) Winsor Letton	Winsor Letton **Date: 5 October 2011**

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1. Introduction and Summary

As early as 1999, when Gulf of Mexico (GoM) deepwater projects passed the one-mile water-depth mark, the importance of advanced technology on the deep sea floor was apparent. In contrast to the comparatively simple exploration and production operations carried out on the continental shelf, similar work in deepwater is exponentially more challenging.

The specific implications on measurement techniques and technology of working in ultra-deepwater are considerable, and have been recognized for many years. Beginning around 2000 - 2005, operators in the GoM began to realize that measurement technology was ill equipped to deal with these future deepwater requirements, and began to discuss what could be done. A group of measurement specialists representing several of the major operators, service companies, and equipment vendors decided to address the issues collectively rather than individually.

In the third quarter of 2005, after a one-day DeepStar workshop to identify deepwater measurement gaps, a cost-time-resources (CTR) form for DeepStar funding was submitted and approved, resulting in the two-year Project 8302, *Improved Multiphase Metering for Subsea Tiebacks*. These gap investigations brought together those with interests and skills in the technology to address the issues. The project goals were, however, somewhat limited by budget; funding was not sufficient to fully explore the issues, perform laboratory experiments, build prototype equipment, etc.

During its final year, the DeepStar 8302 Steering Committee attempted to extend the research by submitting a CTR to the Research Partnership to Secure Energy for America (RPSEA). As a requirement of the Energy Act of 2005, the U.S. Department of Energy (DOE) established RPSEA in 2006 to fund promising approaches to innovative E&P technology. Recognizing that improved deepwater measurement is a critical need in the development of America's reserves, RPSEA in 2008 awarded a contract to the Letton-Hall Group (LHG) for Project 07121-1301, *Improvements to Deepwater Subsea Measurement*, to address gaps in deployment and use of multiphase and wet gas meter technology in deepwater production systems. The DeepStar work had been a key precursor to the RPSEA effort – essentially the

"pre-project", in which the stage was set for a project with greater depth. More on the DeepStar Project 8302 can be found in Reference [1].

Six RPSEA Project 07121-1301 Tasks were identified as pivotal in closing the gaps:

- **Deepwater Subsea Sampling.** Development of methods for standardized deepwater well fluid sampling
- **ROV-Assisted Subsea Measurement.** Development of techniques for conveyance by ROV of clamp-on measurement to the sea floor
- **HPHT Sensor Qualification.** Development and qualification of DP sensors for high pressure - high temperature (HPHT) applications
- **Evaluation of Flow Modeling.** Evaluation of the effectiveness of wellbore flow models, such as virtual flow meters
- **Meter Fouling Effects.** Understanding of how fouling of meters affects their response
- **Metering System Uncertainty**. Development of tools to model uncertainties in a subsea-topside measurement system

Work on these six tasks began in October 2008.

2. Motivation for Deepwater Subsea Measurement R&D

Before considering the specifics of the RPSEA Project 07121-1301, the reasons for subsea measurement should be considered. In particular, the question of why measurement should be made at the sea floor rather than topside should be answered.

Although there are many reasons for subsea metering, the most universal is simply this: the world of deepwater production is driven by economics. The cost of equipment rules how the fluids will be produced and conveyed to the surface, forcing measurement practices to adapt to this reality. Given the fact that the cost of deepwater, high-pressure oil or gas flowlines are typically $10 – 20 million per mile, the business driver here is clear, viz., minimize the need for subsea pipelines in any given situation. By commingling production as soon as feasible, test lines – commonly used in shallower waters – can be eliminated, saving tens of millions of dollars.

The implications of commingling on well flow measurement are significant, however. Tests on individual wells through production flowlines are simply not practical, mostly due to the

cost of deferring production from wells not on test. Thus, one is inevitably led to the conclusion that in deepwater scenarios some form of local subsea measurement is the only practical way to obtain individual well rates.

But one must question how reliably the measurement of multiphase flow from each well can be made. Can a meter that was installed on a well at the startup of the field be relied upon to give reasonable oil, gas, and water flow rates measurements five, ten, or twenty years later? Is it possible that something will change? Might the properties of the produced fluids have changed? Perhaps the well has produced substances that now coat the inner walls of the meter, and if so will the meter's normal response be altered?

The important point is that conditions likely will change with the passage of time. Whether due to the properties of the fluid or the condition of the meter itself, responses of multiphase flow meters change over time, and not always in a small way. When one considers the possible costs of poor measurement, understanding what is required for proper flow rate measurement is clearly of crucial importance.

3. Organization and Finance

The CTR for 07121-1301 was submitted in April 2007, as the seminal work of DeepStar Project 8302 was entering its final stages. The DeepStar effort was populated by many of the same operator-experts who later signed on with RPSEA, and helped to define the gaps that 07121-1301 has sought to address.

The CTR was selected for funding by RPSEA in the summer of 2007. By the fall of 2008, LHG had been selected for the work and organized a Joint Industry Project (JIP) to provide the required co-funding.

Since RPSEA required that 20 percent of the total cost of the project be provided by some form of co-funding, the mechanism for doing this was a consortium of oil companies with interests in deepwater production. Each JIP member pledged $150,000 for this purpose. The founding members were:

- BHP Billiton
- BP
- Chevron

- ConocoPhillips
- Shell
- StatoilHydro (now Statoil)
- Total

In addition to their agreement to co-fund the developments, each JIP member agreed to provide their deepwater technological knowledge and experience through the Working Groups for each of the six tasks. This has been crucial to the success of the work, as the knowledge of subsea measurement and related operations is extremely scarce.

The project was proposed and organized as six technical Tasks, plus one additional Task intended for supporting activities such as Management, Reporting, JIP Organization, and Technology Transfer.

The Tasks were:

1. Subsea Sampling
2. ROV-Conveyed Measurement
3. HPHT Sensor Qualification
4. Flow Model Evaluation
5. Meter Fouling Effects on Measurement
6. Measurement Uncertainty
7. Project Management, Reporting, and Technology Transfer.

An important aspect of the execution of each Task was organizing a team to execute the plan. The important team members were the:

- Task Champion. A technologist provided by one of the JIP members.
- Task Manager. An LHG technologist assigned to manage the effort.
- Task Working Group. JIP members who had special interest in the Task technology or application.
- Subcontractors. Each of the Tasks employed one or more subcontracted specialists to perform parts of the work.

The $4.5 million budget for the seven Tasks of 07121-1301 was distributed as shown in the Table 1 below.

RPSEA Ultra Deepwater Program - Project 07121-1301

Project Cost Details

	*Estimated Labor Costs	Estimated Material Costs	Estimated Other Direct Costs	Estimated Travel	Estimated Consultants	Estimated Special Testing	Estimated Subcontracted Effort	G & A	Cost Share Amount (%)	Cost Share Amount ($)	Net RPSEA Cost ($)	Total Estimated Cost
Task 1 - Deepwater Subsea Sampling	$211,275	$56,000	$0	$12,699	$40,000	$76,100	$535,910	$9,000	20%	$188,197	$752,787	**$940,984**
Task 2 - ROV - Assisted Subsea Measurement	$224,325	$250,000	$0	$4,460	$45,000	$100,000	$571,575	$10,000	20%	$241,072	$964,288	**$1,205,360**
Task 3 - HP/HT Qualification	$234,800	$0	$40,000	$45,561	$0	$45,500	$399,889	$7,000	20%	$154,550	$618,200	**$772,750**
Task 4 - Evaluation of Flow Modeling	$175,280	$0	$20,000	$16,633	$0	$0	$230,000	$5,000	20%	$89,383	$357,530	**$446,913**
Task 5 - Meter Fouling Effects	$170,775	$60,000	$0	$5,129	$0	$130,000	$180,000	$5,000	20%	$110,181	$440,723	**$550,904**
Task 6 - Metering System Uncertainty	$143,550	$0	$0	$14,203	$0	$0	$300,000	$4,000	20%	$92,351	$369,402	**$461,753**
Task 7 - Project Management, Reporting and Tech. Transfer	$81,225	$0	$0	$40,269	$0	$0	$0	$0	20%	$24,299	$97,195	**$121,494**
TOTALS	$1,241,230	$366,000	$60,000	$138,954	$85,000	$351,600	$2,217,374	$40,000		**$900,032**	**$3,600,126**	**$4,500,158**

Table 1. Project 07121-1301 Costs Predicted in 2008

It should be noted that, of the $4.5 million total budget, 80% ($3.6 million) was provided by RPSEA and 20% ($900,000) by the JIP. In point of fact, each of the seven companies listed above joined at a fee of $150,000, so the funds made available by the JIP were actually $1,050,000.

4. Tasks. Summary of Results

In what follows, a brief summary of each of the Tasks is presented, along with a short discussion of Task activities and results. For more complete information on the details of the work, the reader is encouraged to read the final report specific to each Task.

4.1 Task 1 – Deepwater Subsea Sampling

In this task, existing sample systems and conceptual designs of sampling systems deployed via ROV were to be reviewed for their potential as standardized sampling systems. A candidate system was to be selected, developed, and tested with an ROV. Draft standards for sampling connections (interfaces), tools, equipment, and operations were to be developed.

All Task objectives were realized. After selection of the concept from the eleven that were considered and the prototype equipment was designed and fabricated, the unit was first tested in the high-pressure multiphase flow loop at Southwest Research Institute (SwRI) in San Antonio, Texas, and later at the Oceaneering (OII) subsea simulation facility in Morgan City, Louisiana. The SwRI test was used to test the fluid dynamics of the sampling process, with samples being captured at six different points in a typical subsea piping arrangement and later compared to reference samples acquired by commercial sampling vendors. The OII Morgan City test was used to evaluate the operability of the sampling system when being manipulated by a commercial ROV in a marine environment.

In order to encourage other ROV and sample system vendors to enter this important area of technology, the specifics of the ROV sampling system interface have been published as a *de facto* standard.

4.2 Task 2 – ROV-Assisted Subsea Measurement

The objective of Task 2 was to deliver supplemental measurement to a multiphase metering site in the subsea pipework in order to verify correct operation of meters that are in place there. More specifically, it is to: (a) understand what can be expected in the deepwater from available sensor systems, (b) identify present and future constraints on ROV operability in these applications, and (c) develop landing zone and sensor system specifications for ROV-conveyed measurement. Another important goal of the project was that the key pieces

developed for the ROV to secure the measurement equipment to the flowline in a predictable and repeatable way would be made public, so that future users of the technology can choose or change their preferred providers of ROV services and measurement technologies.

These goals were met. After the Task Working Group approved the concept and the prototype system was designed, tests were conducted at the Oceaneering (OII) shop in Houston, Texas (source-receiver alignment sensitivity), the SwRI high-pressure multiphase flow loop in San Antonio (measurement performance under various flow regimes, comparison of differences between metering when surrounded by water versus air), and the subsea simulation facility in Morgan City (operability of the metering system when being manipulated by a commercial ROV in a subsea environment).

The specifics of the interface between the ROV-conveyed meter and the flowline (i.e., the landing zone) have been published as a *de facto* standard in order to encourage other ROV and sample system vendors to enter this highly important technology arena.

4.3 Task 3 - HPHT Sensor Qualification

The initial objective of Task 3 was to address the serious operational restrictions that prevented use of the most commonly utilized sensors in multiphase and wet-gas flow meters, i.e., those that measure pressure (P), temperature (T) and differential pressure (DP). A program was to be formulated to increase the P-T-DP operational envelope of these key sensors – currently limited to 10,000 psi and 125 ℃ – by a new design aimed specifically at this issue. The new sensing elements would then be integrated into transmitter housings designed to meet operational pressures of at least 15,000 psi at an ambient temperature of 250 ℃. The integrated transmitters would then be tested at a special test facility, according to a qualification program developed as part of this Task.

In order to accomplish these objectives, it was decided that a design and fabrication shop specializing in micromachined (MEMS) silicon would be contracted to provide the HPHT pressure and differential pressure sensing elements, which would then be incorporated into pressure cells to be integrated into high-pressure meter housings.

A change in specification was made in the early days of the work based on the Task Working Group's recommendation. Since HPHT pressure sensors already exist, the decision was

made not to attempt to develop a measurement-grade P sensor, but only one that could be used to make common-mode corrections to the DP sensor readings.

The goals of the project have largely been achieved. Two iterations of both the MEMS DP chip and the pressure capsule were required. The MEMS chip was successfully tested over its full DP range at 250 ℃ degC, but at a low common-mode pressure of 4000 psi. The chip was also tested successfully at a common-mode pressure of 10,000 psi. The performance (linearity) of the DP capsule was certified by Chamois Metrology Laboratory over its full 6-bar range to be within +/- 0.04 percent at a common-mode pressure of 1000 psi. The assembled pressure capsule appeared to survive a test pressure of 22,500 psi (1.5 times rated pressure), but performed erratically when the common-mode pressure was reduced to 15,000 psi. Investigation revealed that oil had leaked from the capsule, apparently around the oil-fill plug. The DP HPHT chip appears undamaged. The capsule was refilled with oil for additional testing.

4.4 Task 4 – Evaluation of Flow Modeling

The objective in this Task was to address the gap in documented studies of virtual flow meter (VFM) technology by critically evaluating the performance of current commercial VFMs. This was intended to be done by comparing the predictions of VFMs with both real-world data as well as that from flow simulators. The intent of these evaluations was to document the performance of VFMs as a group, and as generic sub-groups within the larger family, identifying areas of strength and weakness. If successful, the effort would encourage the utilization of VFM technology in monitoring or allocation applications, in those cases where it is an appropriate fit.

Unfortunately, getting actual field data proved so difficult that the team was forced to use only simulated data, constructed from the most commonly used flow simulator, OLGA®.

In order to enlist the active cooperation of the commercial VFM vendors, it was agreed that the results of the investigations would be presented in an anonymous fashion, thus avoiding identification of specific vendors. Initially eight vendors agreed to participate.

The results, while interesting, have been less than was desired. Not only was there no field data with which to test the VFMs, but the vendors were less active than had been hoped – in

part because of the lack of real data on which to test their products. Only two of the eight vendors completed the three rounds of tests that were generated by the OLGA® simulator.

4.5 Task 5 –Meter Fouling Effects

This work addressed gaps in understanding the ways in which production alteration of meters affects their responses. It is well known from field operations that meters can become fouled or altered by deposits of scale, wax, asphaltenes, and hydrates, as well as from the processes of corrosion and erosion. The effects of these accumulations on measurement are not well comprehended, thus the primary objective of the work was to understand their nature and magnitude.

The original plan was to perform experiments to evaluate the effects of alteration on some commonly used multiphase meter elements such as Venturi, Cone, and wedge. Alteration mechanisms would be either deposition (scale or wax) or erosion. The Task Working Group (WG) agreed that scale was the major deposition problem in deepwater, and that erosion was the next most important issue; therefore, these were the two phenomena chosen for investigation. Through the generosity of ConocoPhillips, an experimental data set for sand erosion in a Venturi meter was made available at the start of work. Additionally, the WG made an early key decision to use computational fluid dynamics (CFD) "experiments" to augment the laboratory measurements.

The resultant research program included both lab and CFD experiments run on Venturi, cone, and wedge meters, for both scale build-up and erosional effects, the latter in both liquid and gas mixtures.

The results have surpassed original expectations. Not only were there a number of unexpected results uncovered, but once the CFD had been "tuned" to the experimental data, it was able to extend the useful information over a far wider range than was possible by looking only at the lab results.

For more details on the use of CFD in this task, the reader is referred to [2].

4.6 Task 6 – Metering System Uncertainty

The intent of this task was to develop methods to provide users the ability to calculate the uncertainty in flow measurement at the subsea meter, the topside separator, and other

points in between. Merging carefully developed models of multiphase flow with separator and meter models in a unified system has provided a useful tool for the production engineer.

Uncertainty performance of the various components of the system – downhole and subsea pressure and temperature sensors, subsea or topside multiphase meters, a length of tieback pipeline, a topside separator with single-phase flow and watercut meters – are input into the system through spreadsheets, as is the system geometry.

The tool uses separate models for gas-dominant and liquid-dominant systems. Base cases were built to cover typical subsea measurement system configurations. The tool provides a Forward Model, used primarily for uncertainty estimation. In the future, a Backward Model may be developed, which will attempt to identify a source of material imbalance in the system if the balance is outside its expected bounds.

5. Finances

Although the final totals have not yet been computed, the numbers shown in Table 2 are very near what they ultimately will be. The final figures will be slightly different due to (1) a small number of charges that will come in subsequent to the publication of this report and (2) an adjustment of the G&A rate charged based on a final accounting of all project costs.

In looking at the total project spending, it can be seen that Task spending was within the budget in for all six technical Tasks. Only on Task 7, Project Management, Reporting, and Technology Transfer, was the Task budget exceeded. Once Project 07121-1301 was underway and managers began to legitimately charge their non-task-related time to Task 7, it became clear that the Task was severely underfunded – there was simply more management overhead required to do a proper job of running the project than had been anticipated.

Table 2. RPSEA Ultra Deepwater Project 07121-1301

Project Costs by Task through November 2011

SUMMARY OF COSTS	Total Estimated Cost Through November 2011	Original Total Estimated Cost
Task 1 – Deepwater Subsea Sampling	$846,224	$940,984
Task 2 – ROV-Assisted Subsea Measurement	$1,197,027	$1,205,360
Task 3 – HPHT Sensor Qualification	$588,482	$772,750
Task 4 – Evaluation of Flow Modeling	$347,652	$446,913
Task 5 – Meter Fouling Effects	$443,329	$550,904
Task 6 – Metering System Uncertainty	$455,566	$461,753
Task 7 – Project Management and Technology Transfer	$397,130	$121,494
TOTALS	$4,275,410	$4,500,158

It was therefore necessary to maintain extremely tight fiscal control over each Task, seizing those opportunities where savings could be made. By doing so, the project execution was able to proceed according to plan and still satisfy the extra demands required for management. While savings were made on each of the six technical Tasks, a few large savings are worth noting. In Task 5 on Meter Fouling Effects, several significant savings combined to bring the Task cost down by over $100,000. Meters used in the Task were either borrowed from major manufacturers (e.g., Cameron for cone meters) in exchange for the data collected or purchased from very low-cost vendors (Venturi meters). Additionally, the Task was the beneficiary of a data set donated by JIP Member ConocoPhillips that otherwise would have required $50,000 or more to acquire. Finally, using CFD modeling in place of some experiments saved the Task funds and provided more information than lab experiments would have done. Similarly, changes in scope by each Task's Working Group to reflect practical realities permitted each Task to be accomplished at a lower than planned price.

It should be noted that one of the largest savings was on Task 4, primarily due to the inability to achieve the lofty goals set out in the original plan for the Task. Without the numerous rounds of testing on real-world data sets that had been planned, the Task spent far less time and money on only the simulated data created by OLGA® and on tabulating the results from the fewer numbers of vendors who participated.

However, it is clear that achieving the Project goals has been achieved within the budgets of both RPSEA and the JIP – a significant achievement when one considers the size and complexity of the entire undertaking.

6. Project Information

As one would expect, an enormous amount of information has been produced as a result of these six Tasks. Based on the relationships between the Letton-Hall Group, RPSEA, the JIP Members, and the Project sub-contractors, this information falls into one of the three classes defined below.

Public Information. This is the information that is freely available to any person or organization that requests it. Included are this report, the Final Reports for each of the six technical Tasks, presentations made at the 07121-1301 Public Workshop that was held on 21 June, 2011, and certain other Task deliverables so identified. All of this information can be accessed online through publically available links.

Confidential Information. This is certain information available only to the members of the RPSEA Joint Industry Project (JIP) or to designated RPSEA employees. Stored on the Project's Content Management System (CMS), it consists of test results, design drawings, figures, illustrations, etc. that generally complete a more detailed picture of the results of the various Tasks. Access to the CMS by JIP members and designated RPSEA employees is through password protection subject to the confidentiality provisions of the JIP agreements.

Proprietary Information. This is information that is the property of the Letton-Hall Group or another entity through contractual agreements, and to which only LHG or the appropriate entity has access. Examples of this are the design documents for the HPHT DP sensor and the information comprising its manufacturing file. Access to this class of information is only by permission from the owner.

7. Conclusions

The results shown in the Final Reports for the six technical Tasks that comprise 07121-1301 demonstrate that this pioneering RPSEA Project has been a large success. Significant accomplishments are noted below. Letton-Hall Group and its partners:

- Achieved the cooperation of seven of the World's major deepwater operators in addressing a problem recognized by all as crucial, i.e., flow subsea measurement.
- Made the subsea industry aware of the need for sampling strategies and mechanisms for sampling production streams in deepwater. We also developed a means for implementing sampling subsea, while not incurring any potential patent liability.
- Developed the first means using an ROV for conveying clamp-on flow measurement equipment to the sea floor and deploying it there.
- Developed the industry's first HPHT differential sensor for use in deepwater.
- Developed a methodology for evaluating virtual flow meters. This will be of use in the VFM evaluation part of RPSEA Project 10121-4304-01.
- Created the first catalog of fouling effects (erosion, scale) on flow measurement through differential meters (Venturi, cone, wedge).
- Developed a software simulation tool whereby the flow rate uncertainty in a multiphase pipeline network can be modeled, and the uncertainties of various important quantities (e.g., system balance) can be calculated.

It seems clear that both the Department of Energy and the seven major operators received value for the money spent on this work.

While the gains have been noteworthy, there is still work to be done to maximize the results from the effort, particularly in their application to safety issues in drilling and completion operations. It is anticipated that this will be a major thrust of the new RPSEA 10121-4304-01 Project.

8. Technology Transfer

A key part of the work of the Project has been ensuring that the results of the work were transmitted to those with a need to use them, i.e., Technology Transfer. The efforts in this area are summarized below.

Presentations to Flow Measurement Specialists at NSFMW and ThAW

During the period October 2008 – July 2011, presentations were made at the two main events for specialists in oil and gas flow measurement, i.e., the **North Sea Flow Measurement Workshop** and the **Americas Workshop**.

HALL, J., WEBB, R., and W. LETTON, *Deepwater Measurement Verification – a DeepStar-RPSEA Mandate*, 26th North Sea Flow Measurement Workshop, St. Andrews, Scotland, October 2008.

REMACLE, P., TOSKEY, E., McCOY, R., and W. LETTON, *Technology Paths for Deep Water ROV-Conveyed Multiphase Flow Measurement*, The Americas Workshop, Houston, Texas, 27-29 April 2010.

BARTON, N., ZANKER, K., AND G. STOBIE, *Erosion Effects On Venturi And Cone Meters*, The Americas Workshop, Houston, Texas, 27-29 April 2010.

LETTON, C, PARIS, N., WEBB, B., TING, F., FLOYD, A., TYRRELL, C., AABRO, E., and M. KANE, *Subsea Deepwater Measurement – Technology Gaps and Solutions,* 28th North Sea Flow Measurement Workshop, St. Andrews, Scotland, October 2010.

LETTON, W., *Results from the RPSEA Deepwater Measurement Project*, The Americas Workshop, The Woodlands, Texas, 26 – 28 April 2011.

KANE, M., AND E. TOSKEY, *ROV-Assisted Subsea Measurement – A First Attempt*, The Americas

Workshop, The Woodlands, Texas, 26 – 28 April 2011.

KELNER, E., AND T. MORROW, *Development and Testing of an ROV-Deployed Deep Water Subsea Sampling System*, The Americas Workshop, The Woodlands, Texas, 26 – 28 April 2011.

BARTON, N., MACLEOD, M., ZANKER, K., AND G. STOBIE, *Erosion in Subsea Multiphase Flow Meters*, The Americas Workshop, The Woodlands, Texas, 26 – 28 April 2011.

BARTON, N., ZANKER, K., AND G. STOBIE. *The Effects of Scale Deposition in Subsea Multiphase Flow Meters,* 29th North Sea Flow Measurement Workshop, Tonsberg, Norway, 25-28 October 2010.

Presentations at Other Forums

There have been opportunities to make presentations to other groups of oilfield specialists, such as the following.

Offshore Technology Conference 2009. Dr. James E. Hall made a presentation and otherwise participated in a panel session on ultra-deepwater technology and the RPSEA UDW programs. In addition, the Letton-Hall Group manned the RPSEA exhibition booth for half a day, explaining the 07121-1301 Project to those interested persons who stopped by.

Gulf Coast Measurement Society 2010. In November 2009, Mr. Eric Kelner made an invited presentation to this group of mostly mid-stream measurement specialists on the importance of upstream measurement, especially subsea, and how the RPSEA 07121-1301 Project was addressing measurement gaps there.

RPSEA Ultra-Deepwater Technology Conference 2010. Mr. Eric Kelner presented the 07121-1301 Project at this general RPSEA technology meeting in June 2010.

Multiphase Measurement Roundtable. In June 2010, Mr. Eric Toskey was invited by the organizers of this meeting to give a presentation on subsea measurement in general, and on the RPSEA 07121-1301 Project in particular.

API Committee on Petroleum Measurement (COPM) Fall Meeting – "Breakfast Talk" – 10/4/2010. Dr. W. Letton spoke to this large (approximately 300) group of mostly non-upstream measurement specialists on the nature and importance of the RPSEA 07121-1301 Project effort.

Offshore Technology Conference 20012. A special session devoted to the 07121-1301 Project

will be held on Tuesday 1 May 2012 from 0930 until noon. An overview presentation followed by those on each of the six tasks will be made.

Journal Publications.

Pipeline and Gas Journal, November 2009. Mr. Eric Kelner wrote a column for this publication touting the need for deepwater measurement in general, and the virtues of the RPSEA 07121-1301 Project in particular. Readers of this magazine are generally from the midstream (pipeline) community.

Offshore Magazine, 2009 Issue. Based on information gained at the OTC, as well as on materials and interviews provided by members of the Letton-Hall Group, an article was published describing many aspects of the RPSEA 07121-1301 Project effort.

A follow-up article is in preparation for publication in early 2012.

RPSEA 07121-1301 Annual Report. This report was made at the end of 2009 to describe progress after the first 14 months of the work of the project to the RPSEA sponsors, the Department of Energy, and the JIP sponsors. Subsequently most of it was used to brief potential bidders on the DW4304 Project on the state of 07121-1301.

Other Events

Public Workshop. An all-day workshop was held on 20 June 2011 to discuss the results of the project with those who were not members of RPSEA or of the 07121-1301 JIP. Held at the BP Helios Plaza in Houston, the event was attended by 63 individuals. Each of the six major task areas was explained in some detail, followed by a period during which those who had led the development answered questions from the audience. PDF versions of the presentations from the day were posted on a website for download by those interested in doing so.

9. Acknowledgment

The authors would like to acknowledge the roles played by their two major sponsors. First, the US Department of Energy, through its RPSEA affiliate, has provided the funding and the impetus for numerous deepwater technology developments, including this one. And second, the member companies of the Joint Industry Project for 07121-1301 – Total, Statoil, Shell, ConocoPhillips,

Chevron, BP, and BHP – provided the co-funding required by RPSEA, as well as the expertise in subsea engineering and measurement necessary to successfully do the work.

10. References

[1] HALL, J., WEBB, R., and W. LETTON. *Deepwater Measurement Verification – a DeepStar-RPSEA Mandate*, 26th North Sea Flow Measurement Workshop, St. Andrews, Scotland, October 2008.

[4] BARTON, N., ZANKER, K., AND G. STOBIE. *Erosion Effects On Venturi And Cone Meters*, The Americas Workshop, Houston, Texas, 27-29 April 2010.

RPSEA

Improvements to Deepwater Subsea Sampling Final Report

07121-1301-Task 1.FINAL

Improvements to Deepwater Subsea Measurement

07121-1301

October 7, 2011

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Abstract

A method for a Remotely Operated Vehicle-operated subsea sampling system has been developed to provide a means to capture representative fluid samples at the subsea multiphase meter and other locations at various times throughout the life of the well. The system has been tested in a laboratory and a tank to simulate ROV deployment in subsea conditions.

One attractive feature of the sampling system is the proposed standardized interface. The standardized interface between the sampling system and the process fluid would relieve users and manufacturers from the costs and complications of proprietary systems with varied designs and procedures. This paper presents an overview of the sampling system development and testing.

Prepared by:	Approved by:
Eric Kelner, P.E. (LHG)	 Date: October 7, 2011

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1. Introduction

The increase in deepwater production in the Gulf of Mexico and other locations around the world has brought a corresponding increase in the use of subsea multiphase flowmeters. The placement of subsea multiphase flowmeters near the well provides improved reservoir management, well diagnostics and allocation. However, multiphase flowmeters require timely, accurate fluid properties, at meter conditions, to realize their full potential. Subsea architectures with long flow lines and risers have led to the realization that well tests and topside samples cannot meet the needs of this new measurement technology.

A method for a Remotely Operated Vehicle (ROV)-operated subsea sampling system has been developed to provide a means to capture representative fluid samples at the multiphase meter and other locations at various times throughout the life of the well. The system has been tested in a laboratory and a tank to simulate ROV deployment in subsea conditions.

One attractive feature of the sampling system is the proposed standardized interface. A standardized interface between the sampling system and the process fluid would relieve users and manufacturers from the costs and complications of proprietary systems with varied designs and procedures. The standardized interface will be made available to interested parties. This paper presents an overview of the sampling system development and testing.

This project was a part of RPSEA Project 07121-1301. Project 07121-1301 consisted of six tasks intended to address technology gaps in deepwater subsea multiphase measurement. Development of a subsea sampling system was one of those projects. The effort was supported by a task group consisting of representatives from BP, BHP Billiton, Chevron, ConocoPhillips, Shell, Statoil, and Total. In addition to monetary support, the Subsea Sampling Task Group actively contributed operations and engineering expertise throughout the development process.

1.1 Motivation

Traditionally, samples are taken from a topside separator. An individual well is isolated, the flowline/riser is flushed with the test well's flow, and the sample is taken when the isolated well stream makes it to the topside separator. When the subsea architecture includes long subsea tiebacks, this process becomes more difficult. This process is problematic for several reasons, 1)

shutting-in wells results in costly deferred production, 2) samples may not be representative due to thermodynamic and hydrodynamic changes as the fluid moves through the long flowline/riser combination and 3) flow assurance concerns (hydrates, wax, asphaltenes) may prohibit this type of sampling altogether.

Multiphase flow meters require accurate fluid properties, such as gas, oil and water density, water conductivity, oil permittivity and mass attenuation for accurate flow measurement. These properties may change throughout the life of the well, reducing the accuracy of the meter. Periodic *in situ* sampling of the fluid flowing through the meter will improve meter accuracy, thereby improving the allocation process, reservoir management and well diagnostic capability.

The need for subsea sampling is not confined to multiphase meters. Other applications that would benefit from subsea sampling include: determination of gas heating value, API Gravity, sulphur content and other fluid properties and quality parameters, detection of contaminants, and regulatory issues, such as when the governing regulatory authority asks for evidence that compositional information provided by the operator in his application is still the case.

Subsea sampling of fluids *in situ* has been done before, but with limited success.[1] Previous efforts relied on sampling systems integrated with the multiphase flow meter. In 1999, Framo provided a multiphase meter with an integrated liquid sampling system for application in the Eastern Trough Area Project. During that project, ROV-assisted liquid sampling was carried out 12 times with success.[2] The current meter includes separate gas and liquid sampling ports.

Another technology, developed in 2003 by Christian Michelsen Research (CMR) and the University of Bergen, was an "autonomous metering station" with an integral sampling system. The intent was to avoid transporting fluid samples via ROV. A later concept using the sampling system as a standalone system, in conjunction with an ROV was proposed. One study mentions the integrated version of the sampler, but does not mention the stand-alone version.[3] The discussion focuses primarily on the determination of fluid properties after sampling and does not mention a stand-alone sampling system. Communication with CMR indicates that the project is still in the research and development stage.

1.2 Improvements to Deepwater Subsea Sampling

The interest in subsea sampling has increased in recent years. Several efforts to develop subsea sampling systems are underway. In 2010, a flow through system in which samples sufficient to support multiphase meters was discussed.[4] Other recent developments include the MARS PS liquid sampling system by Cameron[5] and the Mirmorax Subsea Process Sampling System.[6]

2. Organization

An important aspect of the execution of this task was to pull together a team to execute the plan. The team consisted of:

- Charlie Tyrrell (Shell)-Task Champion. In this role, Mr. Tyrrell served as the lead technical interface between the Joint Industry Project (JIP) members, task manager and subcontractors.
- Eric Kelner, P.E. (LHG) - Task Manager. Mr. Kelner was the overall manager of the effort.
- Task Group. JIP members with particular interest in the Task subject matter: BHP Billiton, BP, ConocoPhillips, Chevron, Shell, Statoil, and Total.
- Subcontractors:
    - Oceaneering Deepwater Technical Solutions (DTS) had responsibility for the detailed design and fabrication of the sampling system and interface, provision of ROVs, assembly of the sampling system, support during flow testing at SwRI and operations testing at the DTS tank test facility.
    - Southwest Research Institute (SwRI) Multiphase Flow Facility supported the evaluation of the prototype subsea sampling system in a three-phase flow of oil/water and gas under controlled process flow conditions.
    - TUV NEL was responsible for modeling the thermodynamics and steady-state flow through the prototype subsea sampler to assess the potential impact of the design on sample integrity.

3. Details of Task Plan

The system was developed as an industry consensus design, drawing from the expertise of several industry leading experts in the area of subsea engineering, multiphase measurement and fluid sampling and analysis.

A disciplined, requirements-driven design approach was used to ensure all stakeholder input was addressed. The initial development step was to conduct a workshop during which the project mission statement, a consensus view of system requirements, design constraints and concept selection criteria were agreed to. Sampling system manufacturers were invited to participate in the workshop.

3.1 Intellectual Property

Patents from major providers in the sampling arena were carefully examined to ensure that the design proposed by this project did not infringe on any existing intellectual property.

3.2 Mission Statement

The mission statement adopted by the JIP for this task was to:

- Develop a field-ready (TRL 5) subsea sampling system that supports subsea metering requirements and provides the essential building blocks, functionality and key interfaces to allow industry to focus on future innovation.
- Define open software and hardware interfaces in general accordance with industry standards.
- Ensure compliance with corporate and regulatory Health, Safety, Security, and Environment requirements.
- Remove barriers to market entry.

3.3 Task 1 Objectives

The specific objectives of Task 1 resulting from the workshop were to:

- Review and evaluate deepwater sampling concepts (*existing and proposed*) and select, develop and/or identify the essential building blocks and key attributes to support subsea metering requirements.
- Develop at least one candidate concept into a prototype deepwater sampling mechanism conveyed via ROV.

- Develop standardized sampling connections to subsea piping and ROV.
- Test the prototype in a subsea test facility and/or flow loop.

3.4 System Requirements

Top level system requirements were agreed on during the initial design workshop. JIP members agreed that the system should:

- Be able to function in subsea environment.
- Operate at process temperatures of 10,000 psig and 250 deg F.
- Not interrupt production while sampling.
- Minimize leak paths and emissions.
- Be safe to handle.
- Be able to collect sufficient amounts of each phase.
- Be ROV-operable.
- Incorporate a standardized interface to the production fluid.

3.5 "Representative" Sample

In supporting subsea metering requirements, rather than typical reservoir engineering requirements, it is not necessary to know the phase fractions. For the purposes of multiphase metering, only the properties of the phases present are required. In this project, a representative sample was redefined as "a sample containing each of the phases present at the meter, to which each phase has the same composition as those at the meter."

4. Execution of Plan

Following the workshop, eleven concepts were generated, along with criteria for judging each concept, based on the requirements developed during the workshop. Each concept's perceived ability to meet 19 requirements in five critical areas (Safety/Risk, Ability to Provide a Representative Sample, Sample Verification, Operation, Cost) was evaluated. Each concept was rated based on its ability to meet the requirements.

The highest rated concept was selected for development. Once the concept was selected, the project moved into the design phase. Design reviews were held at the preliminary design stage and at the final design stage. Analyses and tests were planned and executed with input from the member companies. Member companies were invited to observe all tests.

4.1 Concept of Operation

Several possible operating scenarios were considered. In the end, the group agreed that the subsea sampling system would be deployed and operated with a ROV. The ROV-operated system would travel to the subsea meter, connect to a panel mounted near the meter, and take or retrieve fluid samples. The system would replace filled sample vessels with empty vessels and return the filled vessels to the surface for analysis. The system would allow the ROV to accomplish other tasks while sampling is underway. One or more sampling modules could be deployed and operated by the ROV (Figure 1 through Figure 3). The module would connect to the pipe via a proposed standard interface located somewhere near the multiphase meter or at other locations of interest. The sampling system, meter interface and sampling protocol should be standardized to relieve users and manufacturers from the costs and complications of proprietary systems with varied designs and procedures.

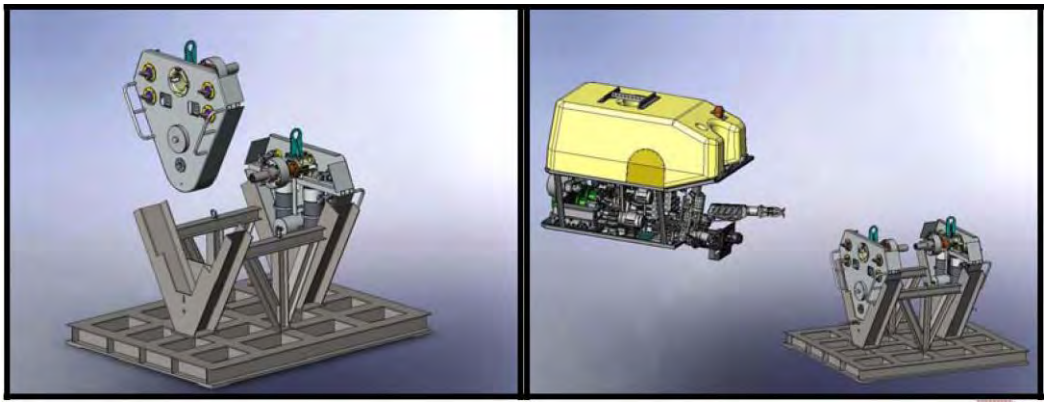

Figure 1. Operational Concept-Subsea Sampler Module and Deployment Frame

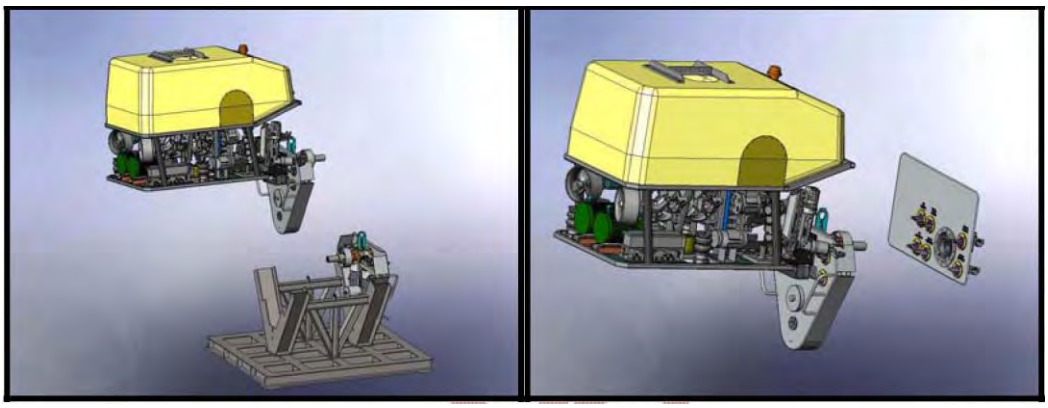

Figure 2. Operational Concept-Sampling Frame Retrieval and Tree Panel Approach

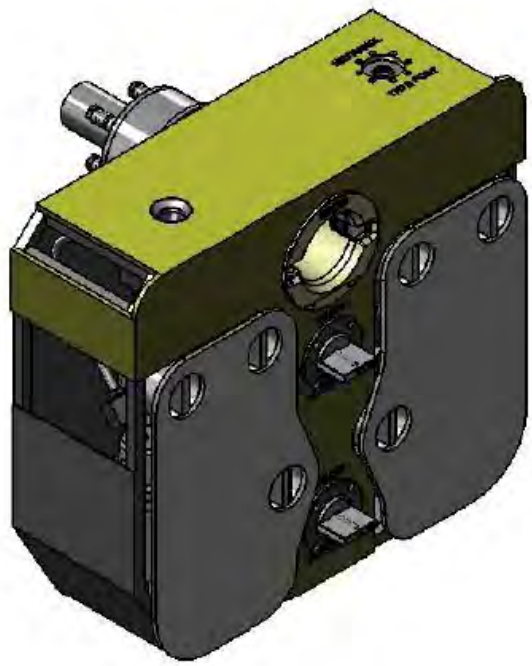

Figure 3. Operational Concept- Sampler Module

4.2 Sampling System

The sampling system concepts are outlined in Appendix B. The design approach selected for development is shown in Figure 4. The flow-through system uses the pressure differential across the production choke or another source of differential pressure to transport the sample through the sample bottle. The system is equipped with a methanol injection line to be used to purge sample lines. Multiple sampling points are selectable.

A photo of the prototype system is shown in Figure 5 . An interface couples the system to the pipe to allow sample collection. The interface uses standard components available throughout the industry, enabling easy reproduction for use in proprietary sampling systems. The system can be operated by a single working class ROV.

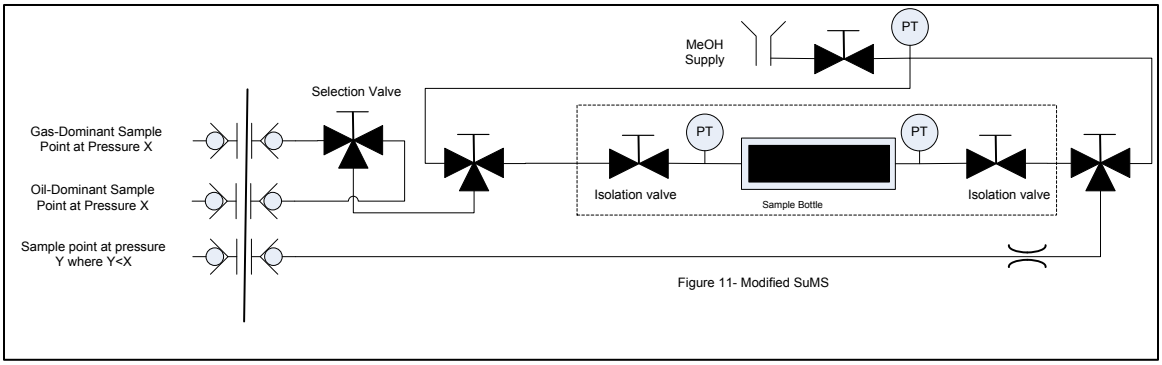

Figure 4. Selected Sampling System Design

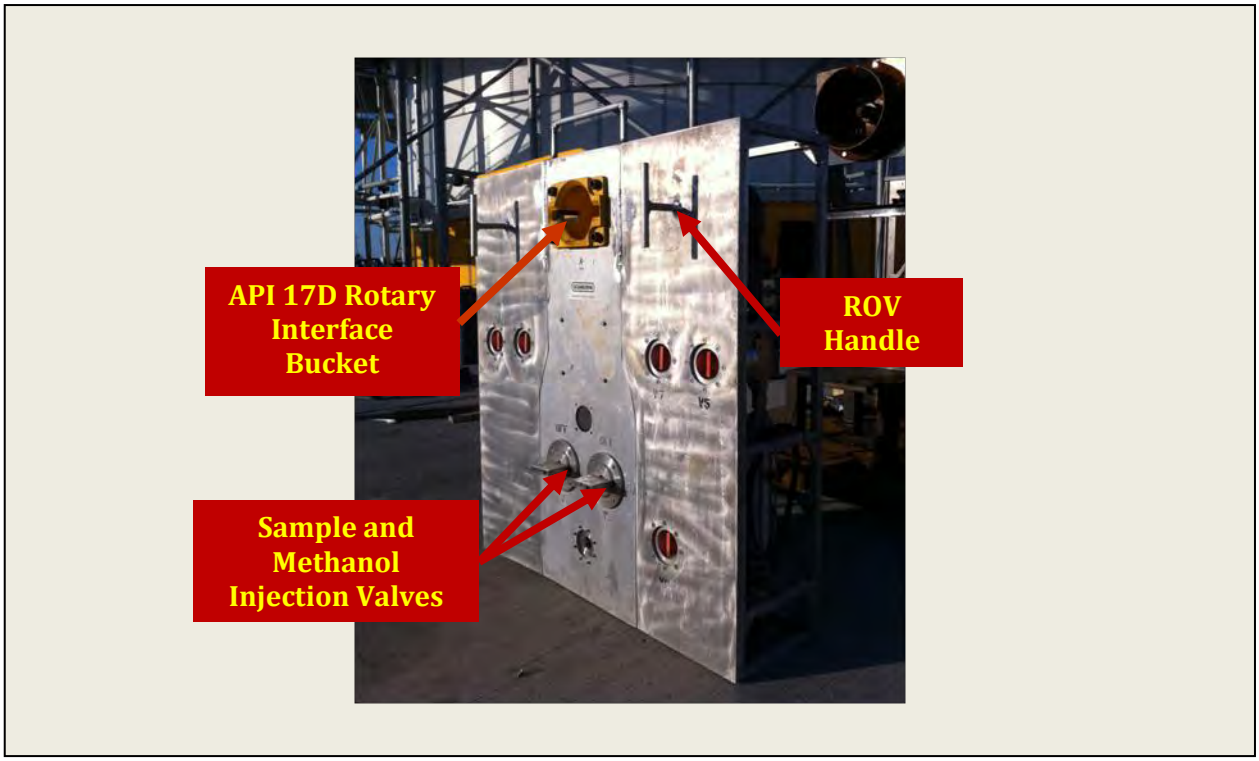

Figure 5. Prototype Subsea Sampling System

4.3 Sampling System Interface

The proposed standard interface (Figure 6, Figure 7, and Figure 8) uses a male/female junction-plate mechanism. The interface consists of the *Sampling-Point Side* and the *Sampling Tool Side*. The Sampling Tool Side is mounted to the sampling system. The Sample Point Side is mounted near the multiphase flow meter. Sample lines are connected from the Sample Point Side to the sample points of interest. The system is manipulated into the Sample Point Side for initial mating by the

ROV. Using a torque tool, the ROV actuates a locking mechanism to couple the two components and establish the fluid connection. Links to the Bill of Materials and Design drawings for the Interface and System are provided in Section 5.2.2.

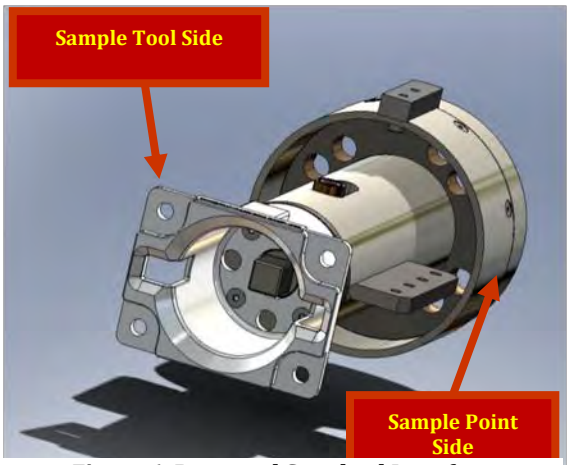

Figure 6. Proposed Standard Interface

Sampling Point Side

The Sampling Point Side is designed to provide access to the process fluid at one or more sampling points. The Sampling Point Side is a bucket design with four National Coupler RS-8 hydraulic couplers mounted at the base plate. It is designed without moving parts or mechanisms that could break or malfunction over time. It has a lock profile mounted to the base plate to allow the Sampling Tool Side to latch onto. This provides the pulling force required to mate the couplers.

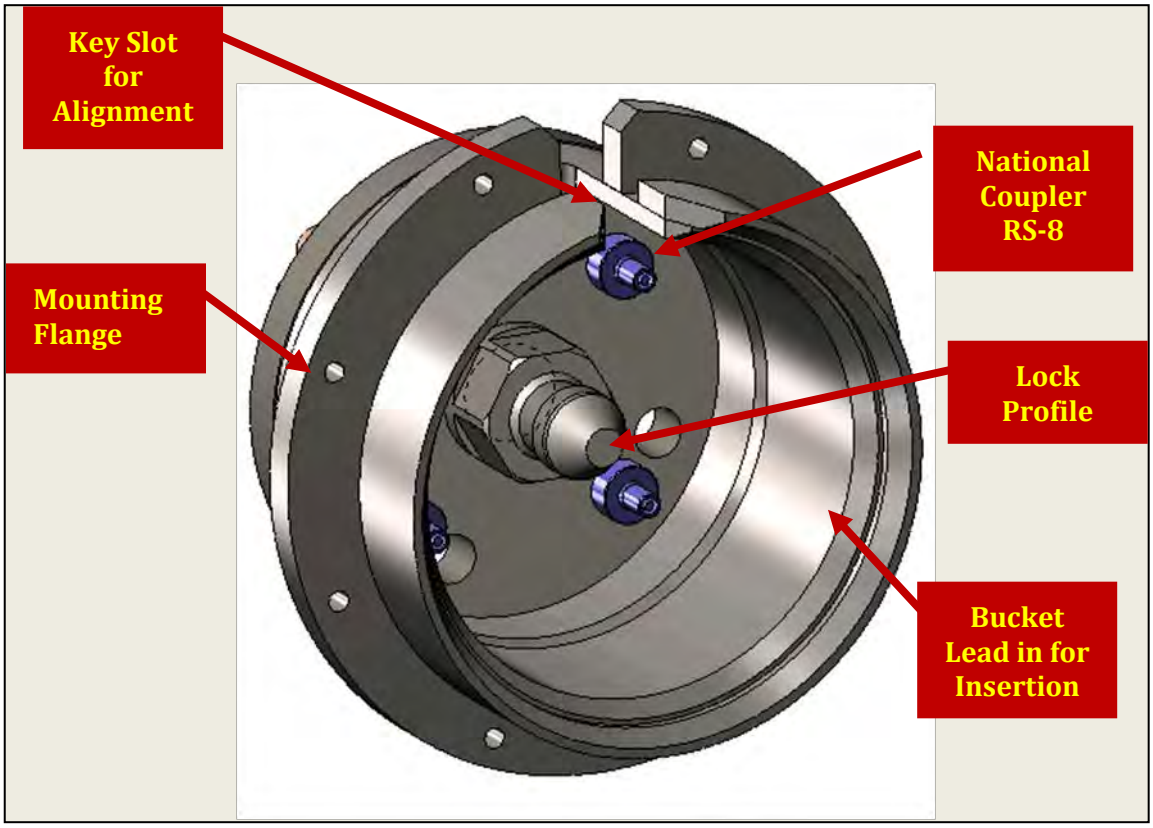

Figure 7. Sampling Point Interface

Sampling Tool Side

The Sampling Tool Side was designed to simultaneously connect four hydraulic subsea couplers reliably using an ROV. The couplers are National Coupler RS-8 Hydraulic Couplers which have widespread use across the subsea industry, especially in subsea hardware control flying leads. The couplers are long lasting and reliable zero leak connectors. They require a large amount of force to mate and demate when the system is under pressure. The sampling interface is designed to mate all four couplers under full 15,000 psig pressure. Test data from National Coupler shows the mating force on each coupler at 15,000 psig internal pressure and 7,500-foot water depth to be 5,200 pounds force (lb_f). The interface was therefore designed to force the couplers together with a force in excess of 21,000 lb_f. The couplers also require force to decouple under some flow conditions. The interface is designed to decouple the couplers with a force in excess of 6,000 lb_f.

The Sampling interface uses an external shroud to both protect and align the coupler set. The external shroud fits into the bucket of the Sampling Point Side. The shroud has two diameters. The leading diameter is smaller to facilitate easier insertion of the tool into the Sampling Point Side, while the trailing diameter is designed to be a tight fit into the bucket and provide fine alignment of the tool in the bucket. The shroud has a large key at the top to provide alignment with a slot cut in the Sampling Point Side. This keyway is designed to withstand the maximum potential torque output of an API 17D Class 4 torque tool (approximately 2,000 ft lbs) to reduce the possibility of damaging the couplers.

The interface uses a 2-inch -4 Acme screw to translate the rotary motion of the torque tool into linear motion. The screw pitch was chosen to provide a mechanical advantage great enough to utilize a manipulator torque tool (approximately 80 ft lbs max) if necessary. The large size was also chosen to prevent buckling of the screw when the tool is being used to demate the couplers. The screw acts on an 8 finger collet that latches over the lock profile on the Sampling Point Side. The collet will expand over the lock profile when the tool is fully inserted. As the screw is turned clockwise, the collet will be backed by the support nose of the tool. Once supported, the only way for the collet to fail is to: break the fingers in tension, break the lock profile in tension, break the screw in tension, or radially break the support nose of the tool. The parts that are subject to tension are rated for the 2,000 ft lb resultant load with a safety factor not less than 2.

The design method of the Sampling Tool Side progressed by choosing the couplers, in this case 0.5" National Couplers. The design of the Sampling Circuit and the maximum force output required of the system dictated four couplers. The maximum operating torque was chosen as 80 ft lbs to allow the system to be operated with a manipulator torque tool instead of requiring a hydraulic torque tool. Matching the operating torque to the force output yielded a range of screw profiles that would work for this design.

Next, the minimum cross section of the lock profile was chosen based on the properties of 4140 carbon steel at the maximum tensile load of 21,000 lbs. The profile of the lock and length of the collet fingers were chosen by arbitrating a maximum 150 lb_f insertion/removal force and calculating the bending and tensile stresses the fingers were subjected to. The final length and geometry of the fingers was checked for buckling at the 6,000 lb load by Finite Element Analysis (FEA). The FEA indicated the design was safe from buckling. The acme screw profile of 2-inch -4 was chosen out of the results of the torque/force balance to fit the inside diameter of the collet with minimal waste of space.

The main body of the Sampling Tool Side was chosen from standard API pipe that matched the outside diameter (OD) of the collet fingers and API 17D Rotary Interface Bucket. The shroud was chosen from another size of API pipe to provide clearance between the inside diameter (ID) of the shroud and the OD of the main body for the National Couplers. The use of API pipe increased the manufacturability of the tools as well as reducing the cost and complexity of the design by using material widely available throughout the oil and gas industry.

The main body contains the collet, Acme screw, collet support, and bearings. The bearing cap is connected to the main body with eight ¼-inch -20 Stainless Steel Flat Head Cap Screws. The design allows a separation of the collet assembly if the entire system got into a bind. Overtorquing the screw in the counter clockwise direction would cause the interface to separate, allowing the ROV operator to separate the device subsea and remove the device in pieces.

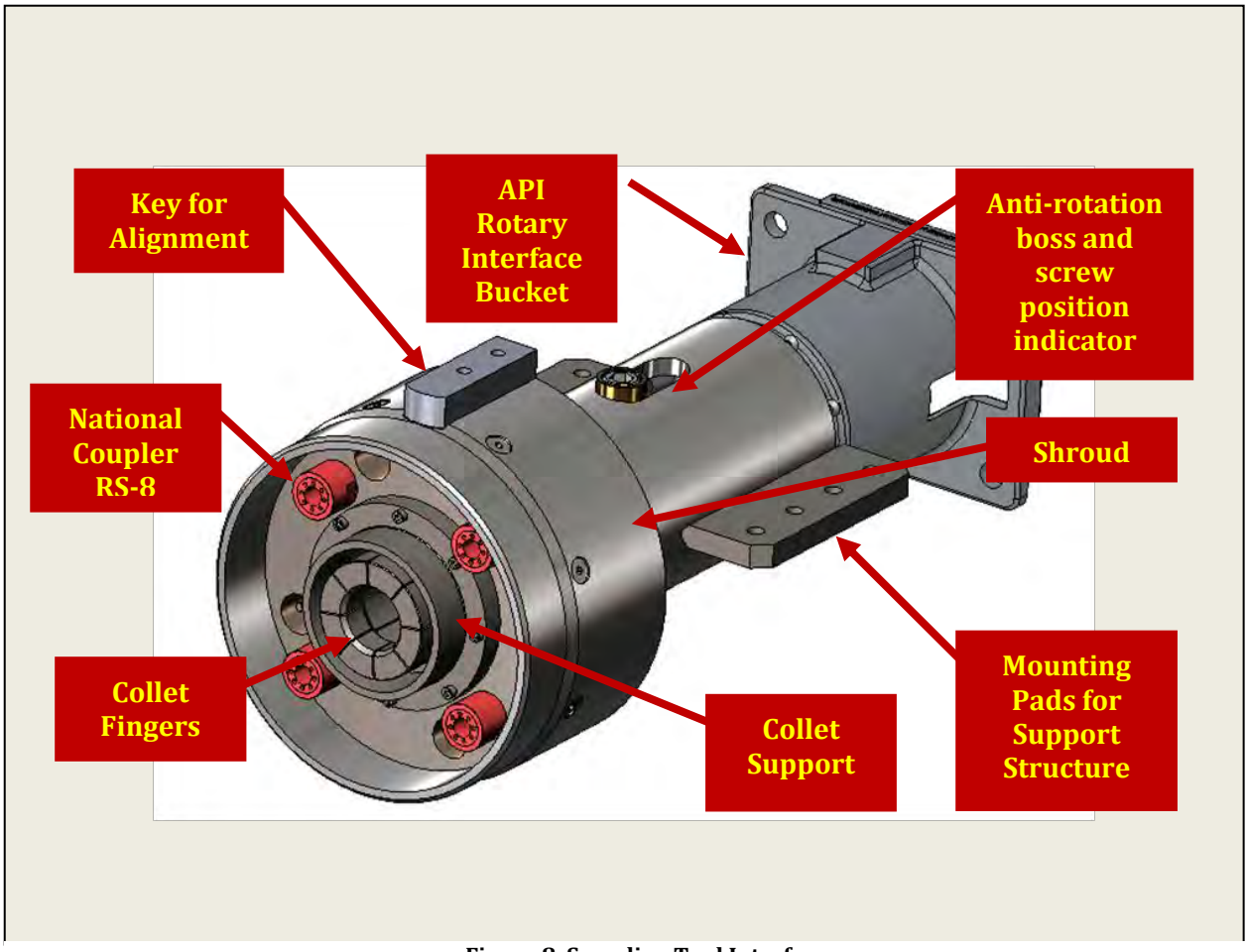

Figure 8. Sampling Tool Interface

4.4 Design Analysis

TUV NEL was contracted to analyze the design to provide insight into the performance of the system during sampling in-situ. The objectives of the analysis were to assess the system's ability to collect a "representative" sample and to identify design features that could impact the system's ability to collect a "representative" sample. The technical approach was to model the overall phase behaviour of a characterized live fluid as it moved through the system.

NEL concluded that the sample system should work as expected. The analysis showed that minimal sample distortion was expected within the sampling system and that sample distortion was dependent on both system and ambient conditions. A link to the full NEL report is given in Section 5.1.

4.5 Testing

Two series of tests were conducted to establish the feasibility of sampling with the system: a flow test and a tank test. The flow test, intended to show that samples could be successfully acquired and that sufficient amounts of process fluids could be collected, was conducted at the Southwest Research Institute's Multiphase Flow Facility located in San Antonio, Texas. The second test, intended to show that the system could be manipulated and successfully coupled in a subsea environment, was conducted at Oceaneering's ROV Test Tank located in Morgan City, Louisiana.

4.5.1 Flow Tests

The objectives of the flow tests were to:

a) Gain confidence in the system's ability to collect oil, gas and water in sufficient amounts,
b) Sample from several locations, collecting samples from at least one gas-rich regime and from at least one oil-rich regime, and
c) Sample at low and high water cut flows.

Since a flow loop test using live fluids was impractical, it was decided to use Drakesol 205, nitrogen, and saline water to model a production fluid. Nitrogen was selected, rather than methane, based on SwRI's concern that the prototype system included non-explosion-proof electrical components.

Table 1. Compositional Makeup of Drakesol 205

Component	Carbon No.	Volume Percent
Undecane	C_{11}	2.9
Dodecane	C_{12}	23.9
Tridecane	C_{13}	49.3
Tetradecane	C_{14}	19.9
Pentadecane	C_{15}	3.5
Hexadecane	C_{16}	0.5

Rather than vary water cut, which would require a significant amount of facility time, it was decided to keep the water cut at a low fraction. The rationale was that if the system could collect a sufficient amount of water at a very low water cut, it certainly could collect enough at higher water cuts.

The approximate test conditions were:

- Liquid flow rate: 1500 barrels per day (bbl/day or B/D) and 4500 B/D.
- Gas volume fraction: 10% and 80%
- Water to liquid ratio: 2%
- Salinity: 3.0%

Liquid flow rate references included a 1-inch Micro Motion model DH100 Coriolis meter, covering the range from 498 bbl/day to 2,523 bbl/day and a 3-inch Micro Motion model DH300 Coriolis meter, covering the range from 898 bbl/day to 4,515 bbl/day.

Figure 9. Determining Watercut

The gas flow rate reference meters included a 3-inch orifice meter, using plates of various beta ratios, and a ½-inch Coriolis meter. The gas flow rate was calculated according to American Gas Association (AGA) Report Nos. 3, 7, and 8. A coalescer filter-separator installed downstream of the horizontal gas/liquid separator removed entrained liquid prior to gas flow measurement.

Once the oil and water flow rates were set, two liquid samples were collect and centrifuged to separate the oil from the water. The watercut from each sample was averaged to determine the reference watercut. Oil and water flow rate and the total system liquid content were adjusted to maintain the target watercut.

Samples of the salt-in-water solution used during the testing were collected and analyzed using a salinity refractometer. Samples collected from the actual flow loop inventory on two test days contained 3.0 weight percent (% wt.) NaCl and 2.8% wt. NaCl, respectively.

Six sample locations, near a "mixing" tee located upstream of a simulated Venturi (fabricated using two reducers) with upward and downward flow, were selected. The locations, shown in Figure 10, were selected to provide differently "biased" samples. Three spot samples were taken at each condition and at each point to provide a reference and a statistical measure of the repeatability of the reference at a given point.

Liquid samples were collected in one liter bottles and separated to estimate the amounts of Drakesol and water in the sample. Gas amounts were estimated using a sight glass installed in the sample cylinder.

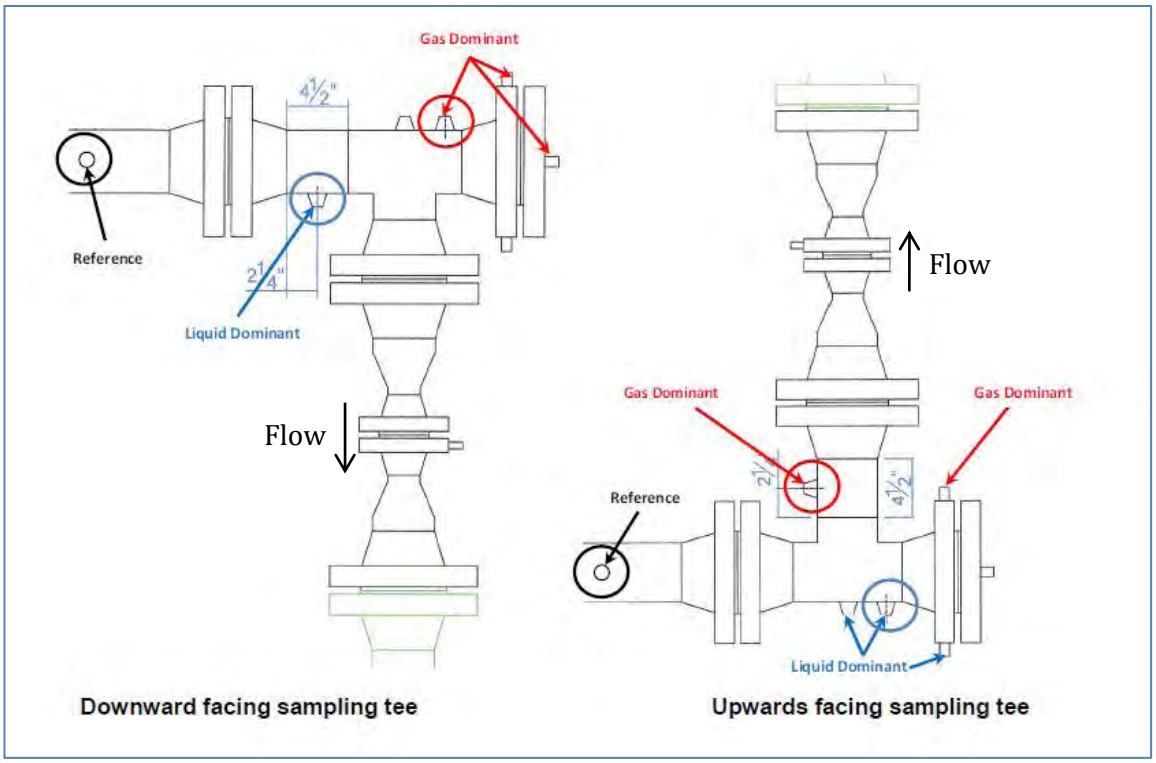

Figure 10. Sample Locations

4.5.2 Tank Test

The system was transported to the Oceaneering ROV Tank Test Facility in Morgan City, Louisiana for tests with an actual ROV. The objective of the tank test was to run through at least one operational cycle consisting of manipulating the system into position on a test stand, making a successful coupling, manipulating the valves, then decoupling and removing the system from the test stand. Figure 11 through Figure 13 show the basic approach.

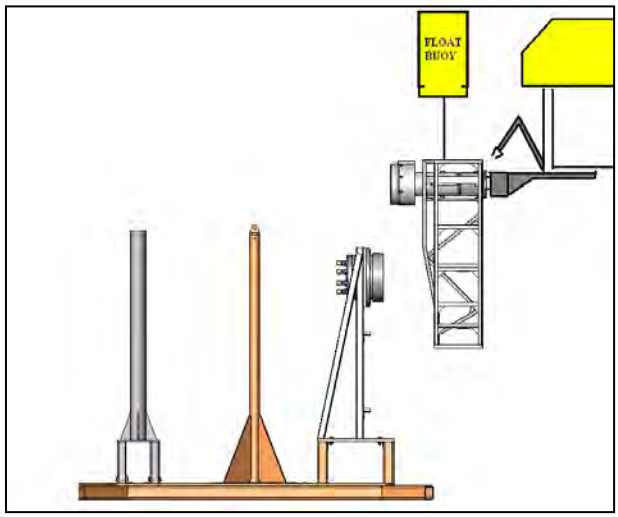

Figure 11. Fly Sampling System to Simulated Sampling Interface

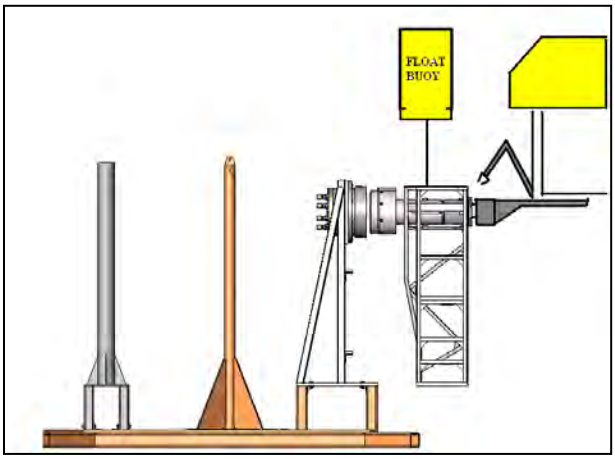

Figure 12. Insert Sampling System into Simulated Sampling Interface

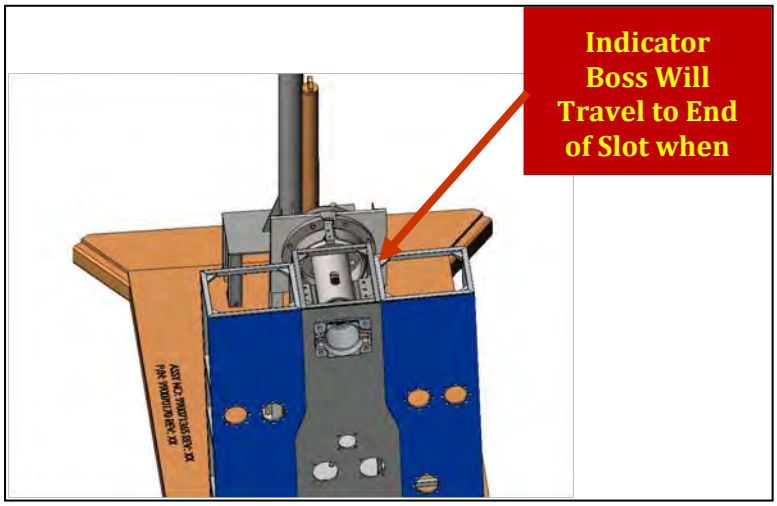

Figure 13. Using Torque Tool, complete connection to Simulated Sampling Interface

The Tank Test Facility is a closed, continuously filtered, fresh water cylindrical tank with a volume of 447,000 gallons. Tank dimensions are 56 foot diameter x 25 foot deep. Four observation windows are located near the bottom of the tank. The ROV (an Oceaneering Millennium Plus), test stand and sampling system were lowered into the tank. The test stand was placed near a tank wall to allow room for the ROV to manoeuvre. After ROV pre-flight tests, the operator moved the system into position on the test stand, successfully coupled it using a torque tool, manipulated the valves, and then decoupled the system from the test stand. Figure 14 through Figure 17 document the tank tests.

Figure 14. Simulated Sampling Interface

Figure 15. Loading Sample System Into Tank

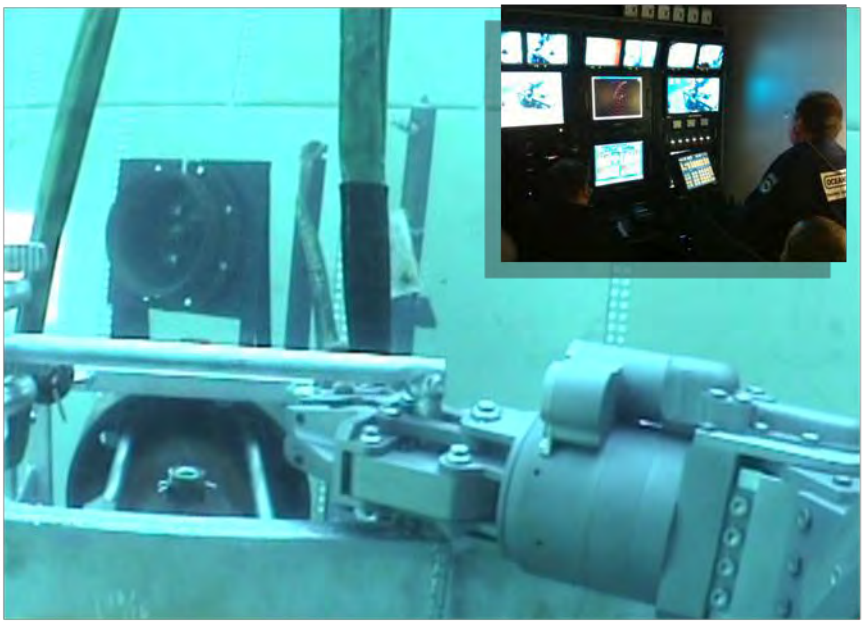

Figure 16. Maneuvering the Sample System Into Position

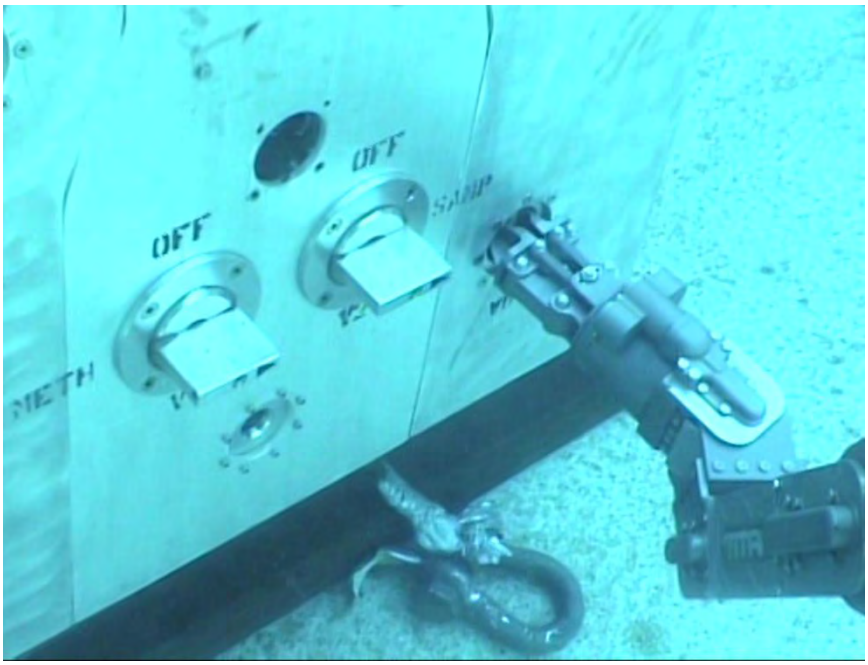

Figure 17. Manipulating the Sample System Valves

5. Results and Deliverables

5.1 Results

TUV NEL Analysis:

- The TUV NEL analysis showed that minimal sample distortion was expected within the sampling system and that sample distortion was dependent on both system and ambient conditions.
- The full report may be obtained at:

  http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=567

SwRI Flowing Tests:

- The flowing tests at SwRI indicated that the relative percentages of oil/water/gas captured in the sampling system will not necessarily be the same as the percentages in the flowing stream.
- The oil/water/gas contents of the two samples are related to the sampling location, the rate of oil and gas flow, the local multiphase flow pattern at the sampling location, and the rate at which the sample is drawn into the sampling system.
- It was possible to collect a significant amount of water, even under low watercut conditions.
- The system performed generally as expected.
- The full report may be obtained at:

  http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=698

Oceaneering Tank Tests:

- Tank tests indicated the system was challenging to manipulate subsea. However, with practice, the operator was able to successfully couple the system and manipulate the sampling valves.
- The system performed generally as expected.
- The full report may be obtained at:
  - http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=837

5.2 Deliverables

5.2.1 ROV-Conveyed Prototype Sampling System with Operations Manual

An assessment of the Technology Readiness Level (TRL) of the system was made using the *TRL Calculator (V 2.2)* developed by William Nolte of the Air Force Research Laboratory. The tool's summary sheet is shown in Figure 18. The Operations and Maintenance Manual may be obtained at: http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=721

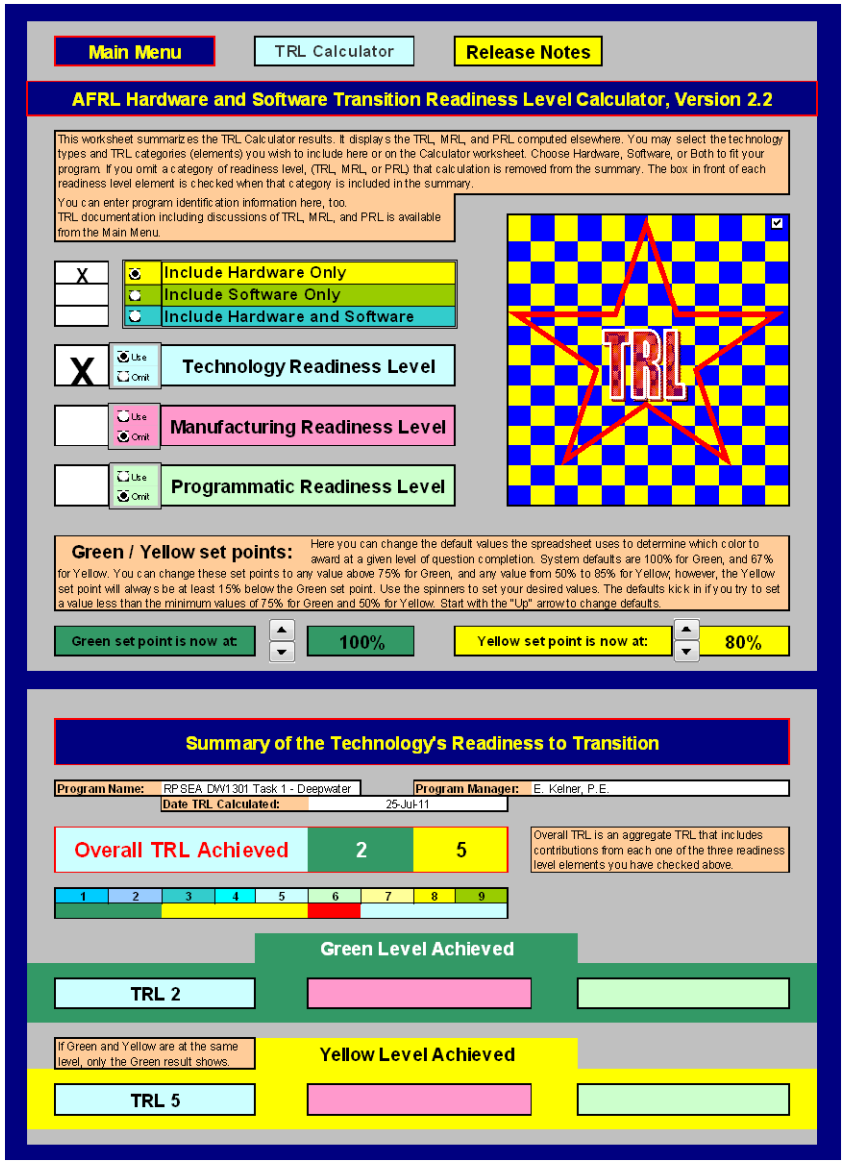

Figure 18. The calculator indicates the sampling system at TRL Level 5 at the 80% acceptance level.

5.2.2 Engineering Design Drawings and Documents

Sampling interface Bill of Materials and Drawing List

A Bill of Materials and Drawing List for the Sampling Interface may be downloaded at:

http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=699.

Sampling Interface Drawings

The Sampling Interface drawings may be found at:

http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=701

Other Design Documentation

Additional drawings and design documents include the following:

- Analyses and calculations including Finite Element Analyses for the collet mechanism and the sample cylinders.
- Electronics bench testing and calibration report.
- The pressure test report from the functional system test carried out prior to the flow tests.

They may be found at the following link:

http://www.rpsea.letton-*hall*.com/tiki-download_file.php?fileId=718

5.2.3 Draft Standards for Piping Connections, Sample Location and Sampling Interface Design

It was initially assumed that the project would yield enough information to prepare draft standards for piping connections, sample location and sample interface design. However, early on in the project, the JIP recognized the magnitude of the work required to identify appropriate sample point locations and piping connections and agreed to limit the scope of the project to the sample system interface and the sampling tool itself. Sample location was briefly investigated as part of the flowing tests conducted at Southwest Research Institute. The results of the sample location investigation are discussed in the flow loop test report. A full disclosure of the sample interface design is included in Section 5.2.2 above.

5.2.4 Sampling Best Practices Guideline

The effort identified the main issues to be addressed in a sampling best practices guideline. Additional investigation is required to provide defensible, industry-consensus best practices for subsea fluid sampling. A straw man standard is provided in Appendix C.

6. Conclusions & Areas for Continued R&D Investigation

In this task, a proof of concept sampling system prototype was developed and tested under flowing and simulated subsea conditions. The task demonstrated the feasibility of subsea sampling using standard working class ROVs and associated equipment. It developed a proposed standard interface that can be used by any sampling system to access production fluids, and began the process of standardizing best practices for subsea sampling. By these measures, the outcome of this task was successful. However, in order to realize the ultimate vision - subsea sampling as a routine part of production operations and maintenance - additional work is needed. Suggestions for future work follow.

The objective of follow-on work should include a refinement of the existing sampling system design in order to address the issues discovered during testing of the prototype system and to provide improved performance. The refined system should be tested *in-situ*, using live production fluids to confirm the system's ability to collect samples for supporting multiphase measurement.

Additional objectives should include further assessment of sampling best practices and should address sample point location selection. To this end, investigations using Computational Fluid Dynamics and experimentation to identify the effect of sampling practices, sample point selection, and sample system design should be conducted.

Finally, the potential for integrating the sampling interface and sampling system with a Blow Out Preventer (BOP) should be investigated. If successful, the interface itself and/or sampling system may prove useful for detection of conditions leading to blowouts.

7. References

[1]DEEPSTAR Project 8302 Report, Subsea Sampling, November 2007.

[2]HUMPHREY, ET. AL., Application of Multiphase Metering in Machar and Monan Fields, Offshore Technology Conference Paper No. 12018.

[3]BAKER, ET.AL., A Novel Subsea On-line Multiphase Fluid Sampling and Analysis System, 5th World Congress on Industrial Process Tomography, September 3-6, 2007.

[4]TYRRELL, C. and N.B.JOSHI, The Role of Subsea Sampling in Multiphase Metering, The Americas Workshop, February 3-5, 2009.

[5]HALL, G., Subsea Liquid Sampling Using Flow-Through Technique, Offshore Technology Conference Paper (OTC 21787), 2011.

[6]GRANSAETHER, E., Subsea Process Sampling – Unlimited Access to a Lifetime of Knowledge and Calibration, May 2010, Mirmorax Publication.

Appendix A: Budget and Finances

Area	Budget	Actual
Letton-Hall Group Cost	$211K	$202K
Oceaneering Subcontract	$536K	$460K
Direct Material	$56K	$0
Testing	$76K	$72K
Consultants	$40K	$43K
Miscellaneous	$22K	$66K
Total	**$941K**	**$843K**

Testing accounts for the flowing tests performed at Southwest Research Institute in San Antonio, Texas. The Oceaneering Subcontract includes the design and fabrication of the sampling system, as well as the tank tests performed at the Oceaneering Tank Test Facility in Morgan City, Louisiana. *Consultants* includes TUV NEL's system design analysis and video editing of the tank tests by Matson Multimedia. *Miscellaneous* includes travel, travel G&A and subcontractors G&A.

Appendix B: Sampling System Design Concepts

In the following evaluations of the eleven possible designs, each category was weighted by the JIP members based on their interpretations of the importance of each category. The category weights total 100.

Within each category, each criterion was assigned a weight such that the sum of these values equaled the category weight.

For each criterion, a score of 1 (lowest) to 5 (highest) was assigned based on the JIP understanding of the importance of that criterion. The resulting weighted score reflected each design's expected ability to meet the requirements.

System 1

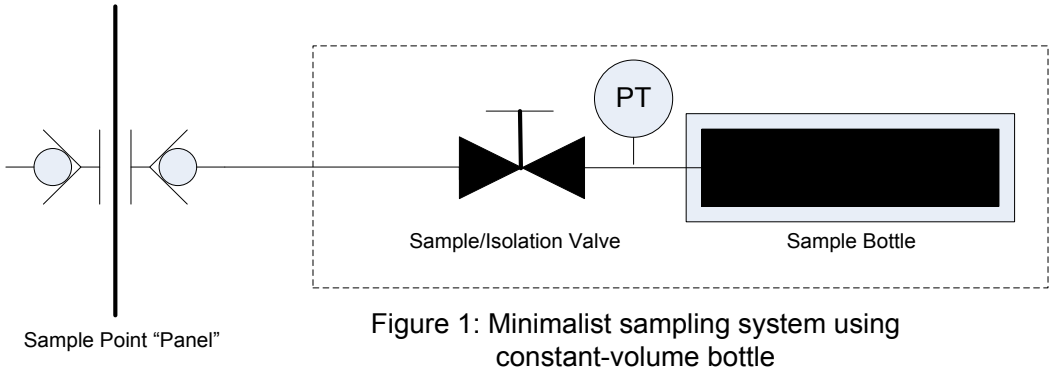

Figure 1: Minimalist sampling system using constant-volume bottle

Definition: A constant-volume cylinder is connected to a subsea sample point (panel with appropriate subsea fluid connector) and fluid is allowed to enter sample bottle once the valve is opened. This is the simplest conceivable sampling device.

Table 2. Assessment of Sampling System Design 1

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	4	32	No slops tank.
Is exposure to high pressure fluids on deck minimized?	8	3	24	Easy to remove/transport
Is risk to asset minimized?	4	4	16	Low risk of release to sea.
Safety/Risk Total	20	11	72	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	1	8	No
Does the system provide an isothermal sample?	8	1	8	No
Does the system prevent hydrates?	4	1	4	No
Is the system tolerant to slugging?	4	1	4	Not inherently. Requires prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	1	6	No. System could have previous sample in lines.
Representative Sample Total	30	5	30	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	1	10	Not obvious, other than P,T
Is the system able to confirm the phases present in the sample?	10	1	10	Not obvious, other than P,T
Sample Verification Total	20	2	20	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning.
Is the system low in complexity?	2	5	10	Yes
Is the system easily operated?	3	5	15	Yes
Is the system easily maintained?	3	5	15	Yes
Can the system take samples at sub-ambient pressure?	3	0	0	No. Requires pump.
Does the system provide the ability to clean/prepare for the next sample?	4	1	4	No.
Operation Total	20	18	49	
Cost/Weight	10			
Minimum Cost?	3	5	15	Minimizes parts.
Minimum Size/Weight?	7	5	35	Yes.
Cost/Weight Total	10	10	50	
Category Weight Total (Weight Must Total 100)	100	46	221	
Total Allocated to Criteria (Must Total 100)	100			

System 2

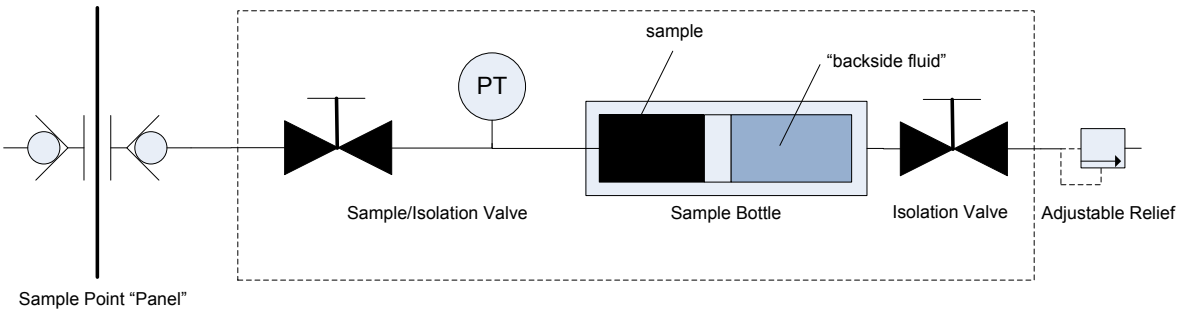

Figure 2: Minimalist sampling system using constant-pressure sample bottle

Definition: A constant-pressure cylinder is connected to a subsea sample point (panel with appropriate subsea fluid connector) and fluid is allowed to enter sample bottle once the valve is opened. Constant pressure is maintained by the relief valve on the opposite side of the piston. The "back side" fluid is either vented to sea or captured in a reservoir. Note: The dashed line indicates a removable, transportable assembly.

Table 3. Assessment of Sampling System Design 2

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	3	24	May require slops tank for backside fluid.
Is exposure to high pressure fluids on deck minimized?	8	3	24	Easy to remove/transport
Is risk to asset minimized?	4	3	12	Adjustable control valve more risky. Discharge to sea undesireable.
Safety/Risk Total	20	9	60	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	5	40	Very controllable.
Does the system provide an isothermal sample?	8	1	8	No obvious temp control.
Does the system prevent hydrates?	4	3	12	Isobaric sample = no dP across system.
Is the system tolerant to slugging?	4	1	4	Not inherently. Requires prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	1	6	No. System could have previous sample in lines.
Representative Sample Total	30	11	70	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	4	40	Sense piston position
Is the system able to confirm the phases present in the sample?	10	1	10	Only P,T sensors shown.
Sample Verification Total	20	5	50	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning
Is the system low in complexity?	2	4	8	Back pressure control adds complexity.
Is the system easily operated?	3	3	9	Back pressure control adds difficulty.
Is the system easily maintained?	3	4	12	
Can the system take samples at sub-ambient pressure?	3	0	0	No. Requires pump.
Does the system provide the ability to clean/prepare for the next sample?	4	1	4	No flushing/cleaning ability.
Operation Total	20	14	38	
Cost/Weight	10			
Minimum Cost?	3	4	12	Floating piston is costly.
Minimum Size/Weight?	7	4	28	Floating piston is heavy.
Cost/Weight Total	10	8	40	
Category Weight Total (Weight Must Total 100)	100	38	198	
Total Allocated to Criteria (Must Total 100)	100			

System 3

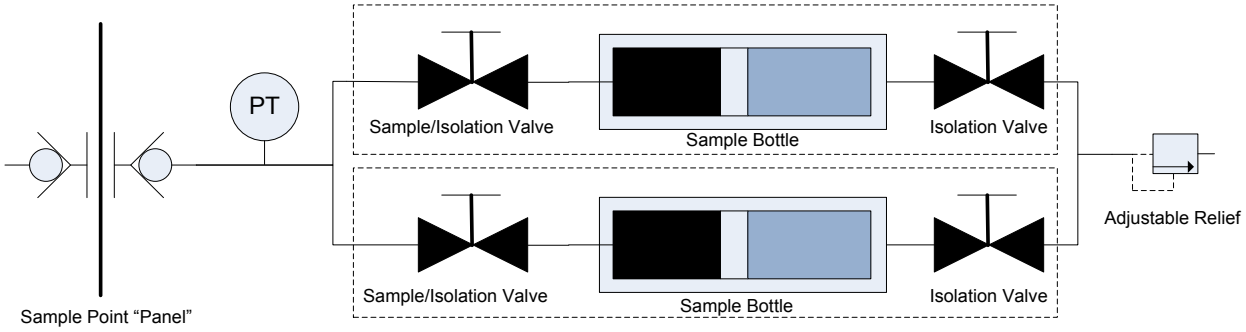

Figure 3: Multiple-Sample bottle system using two constant-pressure sample bottles

Definition: By having two sample bottles and two isolation valves, samples can be taken in two separate bottles, yet still utilize the same pressure control valve (relief). It is assumed that the selection of sample point is done on the subsea sample point panel using the appropriate isolation or selector valves. In this scheme, one bottle may be used as a "slop tank" and is used primarily to clear the lines prior to taking a proper sample in the opposite bottle. Note: The dashed line indicates a removable, transportable assembly.

Table 4. . Assessment of Sampling System Design 3

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	1	8	One cyl. Used as slops tank.
Is exposure to high pressure fluids on deck minimized?	8	3	24	Easy to remove/transport, but two cyls.
Is risk to asset minimized?	4	3	12	Adjustable control valve more risky. Discharge to sea undesireable.
Safety/Risk Total	20	7	44	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	5	40	Very controllable.
Does the system provide an isothermal sample?	8	1	8	No obvious temp control.
Does the system prevent hydrates?	4	3	12	Isobaric sample = no dP across system.
Is the system tolerant to slugging?	4	1	4	Not inherently. Requires prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	3	18	Residue still left in lines.
Representative Sample Total	30	13	82	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	4	40	Sense piston position.
Is the system able to confirm the phases present in the sample?	10	1	10	Only P,T sensors shown.
Sample Verification Total	20	5	50	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning
Is the system low in complexity?	2	3	6	Back pressure control and slops tank add complexity.
Is the system easily operated?	3	3	9	Back pressure control adds difficulty.
Is the system easily maintained?	3	4	12	
Can the system take samples at sub-ambient pressure?	3	0	0	No. Requires Pump
Does the system provide the ability to clean/prepare for the next sample?	4	2	8	Flushing via slops tank.
Operation Total	20	14	40	
Cost/Weight	10			
Minimum Cost?	3	2	6	Floating pistons are costly.
Minimum Size/Weight?	7	2	14	Floating pistons are heavy.
Cost/Weight Total	10	4	20	
Category Weight Total (Weight Must Total 100)	100	43	236	
Total Allocated to Criteria (Must Total 100)	100			

System 4

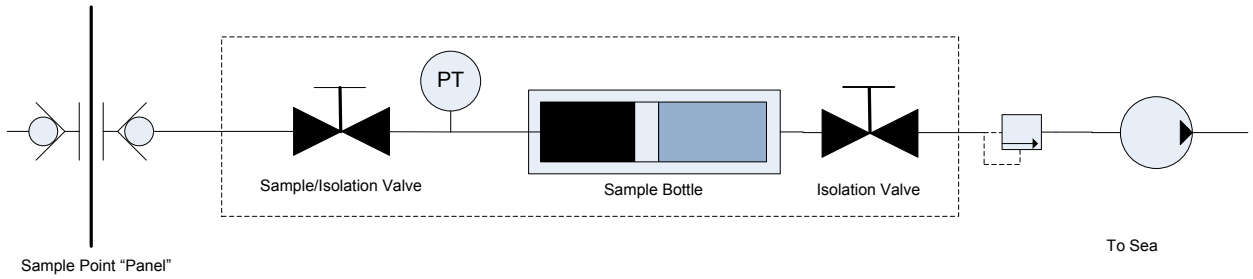

Figure 4: Sub-ambient sampling system using constant-pressure bottle

Definition: A system capable of taking samples at sub-ambient wellbore conditions is enabled by adding a suction pump to the back side of the sample cylinder piston. The "back side" fluid is either pumped to sea or to a reservoir. Note: The dashed line indicates a removable, transportable assembly.

Table 5. Assessment of Sampling System Design 4

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	3	24	May require slops tank for backside fluid.
Is exposure to high pressure fluids on deck minimized?	8	3	24	Easy to remove/transport
Is risk to asset minimized?	4	2	8	Adjustable control valve and pump more risky. Discharge to sea undesireable.
Safety/Risk Total	20	8	56	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	5	40	Very controllable.
Does the system provide an isothermal sample?	8	1	8	No obvious temp control.
Does the system prevent hydrates?	4	3	12	Isobaric sample = no dP across system.
Is the system tolerant to slugging?	4	1	4	Not inherently. Requires prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	1	6	No. System could have previous sample in lines.
Representative Sample Total	30	11	70	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	4	40	Sense piston position.
Is the system able to confirm the phases present in the sample?	10	1	10	Only P,T sensors shown.
Sample Verification Total	20	5	50	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning
Is the system low in complexity?	2	3	6	Pump control adds complexity.
Is the system easily operated?	3	2	6	Pump control adds difficulty.
Is the system easily maintained?	3	3	9	
Can the system take samples at sub-ambient pressure?	3	5	15	Yes.
Does the system provide the ability to clean/prepare for the next sample?	4	1	4	No flushing/cleaning ability.
Operation Total	20	16	45	
Cost/Weight	10			
Minimum Cost?	3	3	9	Pump increases cost.
Minimum Size/Weight?	7	4	28	Floating piston and pump are heavy.
Cost/Weight Total	10	7	37	
Category Weight Total (Weight Must Total 100)	100	47	258	
Total Allocated to Criteria (Must Total 100)	100			

System 5

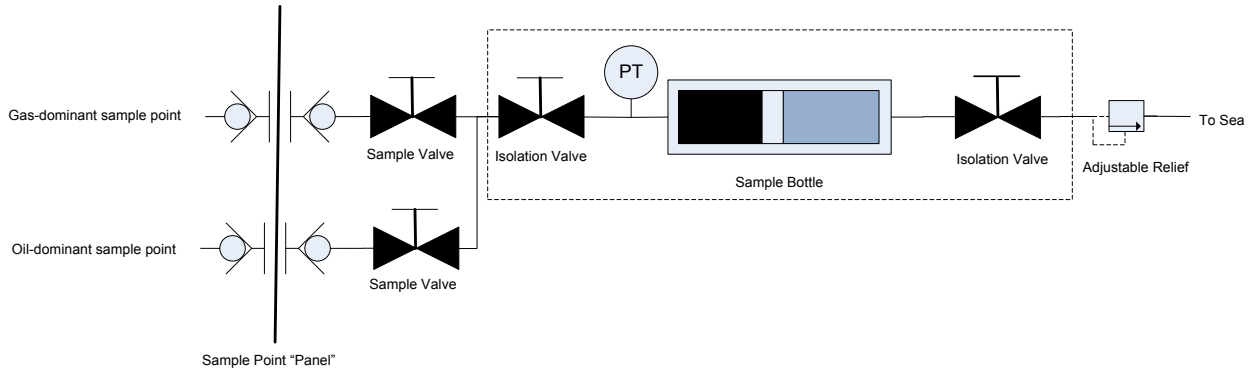

Figure 5: Sampling from multiple sample points into a single bottle.

Definition: This system is designed to take samples from a gas-dominant sampling point and then an oil-dominant sampling point (or vice versa) in order to ensure that sufficient volume of each phase is represented in the sample. However, it is imperative that both sample points be at the same pressure, or that the lower pressure point is sampled first. Note: The dashed line indicates a removable, transportable assembly.

Table 6. Assessment of Sampling System Design 5

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	3	24	May require slops tank for backside fluid.
Is exposure to high pressure fluids on deck minimized?	8	3	24	Easy to remove/transport
Is risk to asset minimized?	4	3	12	Adjustable control valve more risky. Discharge to sea undesireable.
Safety/Risk Total	20	9	60	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	5	40	Very controllable.
Does the system provide an isothermal sample?	8	1	8	No obvious temp control.
Does the system prevent hydrates?	4	3	12	Isobaric sample = no dP across system.
Is the system tolerant to slugging?	4	4	16	Includes prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	1	6	No. System could have previous sample in lines.
Representative Sample Total	30	14	82	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	4	40	Sense piston position.
Is the system able to confirm the phases present in the sample?	10	4	40	Comb. Of P,T and piston position when going from liquid to gas.
Sample Verification Total	20	8	80	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning
Is the system low in complexity?	2	3	6	Back pressure control and addl. Valve add complexity.
Is the system easily operated?	3	2	6	Back pressure control and addl valve add difficulty.
Is the system easily maintained?	3	4	12	
Can the system take samples at sub-ambient pressure?	3	0	0	No. Requires pump.
Does the system provide the ability to clean/prepare for the next sample?	4	1	4	No flushing/cleaning ability.
Operation Total	20	12	33	
Cost/Weight	10			
Minimum Cost?	3	3	9	Additional connection points.
Minimum Size/Weight?	7	4	28	Floating piston is heavy.
Cost/Weight Total	10	7	37	
Category Weight Total (Weight Must Total 100)	100	50	292	
Total Allocated to Criteria (Must Total 100)	100			

System 6

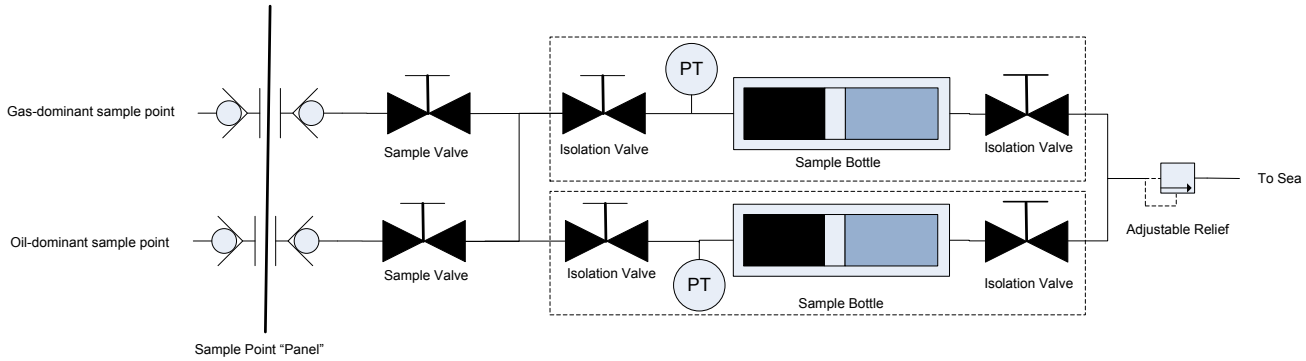

Figure 6: Sampling from multiple sample points into multiple bottles

Definition: This system takes advantage of pressure differential across the production choke to drive the sample through a sample bottle until equilibrium is established. There are multiple sampling points that are selectable. The selection valve can be either in the sampling tool or on the panel. Note: The dashed lines indicate a removable, transportable assembly.

Table 7. Assessment of Sampling System Design 5

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	3	24	May require slops tank for discharge.
Is exposure to high pressure fluids on deck minimized?	8	2	16	Easy to remove/transport, but two cyls.
Is risk to asset minimized?	4	3	12	Adjustable control valve more risky. Discharge to sea undesireable.
Safety/Risk Total	20	8	52	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	5	40	Very controllable.
Does the system provide an isothermal sample?	8	1	8	No obvious temp control.
Does the system prevent hydrates?	4	3	12	Isobaric sample = no dP across system.
Is the system tolerant to slugging?	4	4	16	Includes prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	3	18	Residue still left in lines.
Representative Sample Total	30	16	94	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	4	40	Sense piston position.
Is the system able to confirm the phases present in the sample?	10	4	40	Comb. Of P,T and piston position.
Sample Verification Total	20	8	80	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning
Is the system low in complexity?	2	2	4	Back pressure control, slops tank and addl. Valve add complexity.
Is the system easily operated?	3	2	6	Back pressure control and addl valve add difficulty.
Is the system easily maintained?	3	4	12	
Can the system take samples at sub-ambient pressure?	3	0	0	No. Requires pump.
Does the system provide the ability to clean/prepare for the next sample?	4	1	4	No flushing/cleaning ability.
Operation Total	20	11	31	
Cost/Weight	10			
Minimum Cost?	3	2	6	Floating pistons are costly.
Minimum Size/Weight?	7	2	14	Floating pistons are heavy.
Cost/Weight Total	10	4	20	
Category Weight Total (Weight Must Total 100)	100	47	277	
Total Allocated to Criteria (Must Total 100)	100			

System 7

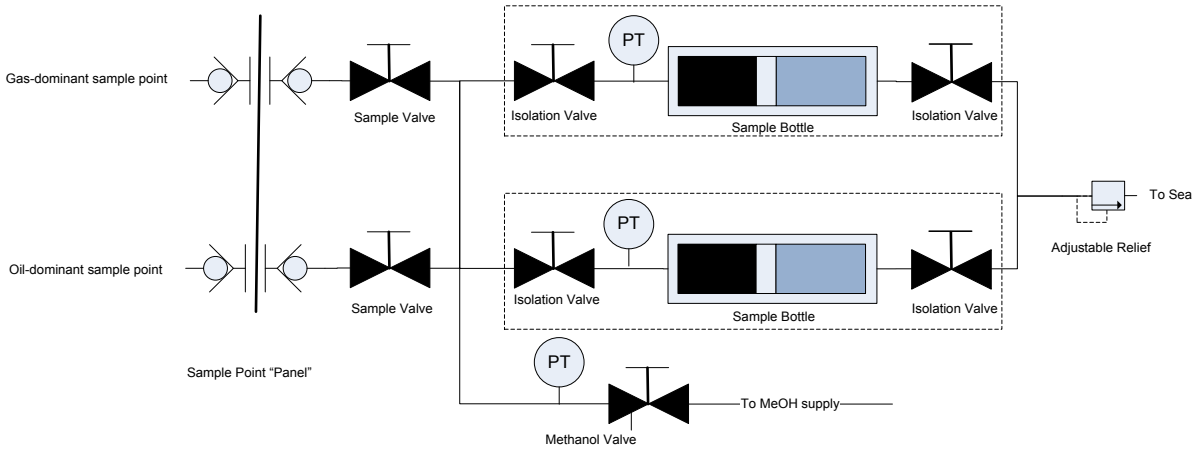

Figure 7: Multi-point sampling with Methanol injection.

Definition: The system used to takes samples from a gas-dominant sampling point and then an oil-dominant sampling point in order to ensure that sufficient volume of each phase is represented in sample. Either bottle can contain the liquid phase, gas phase, or both. This variant is equipped with a methanol injection line to be used to purge sample lines. Note: The dashed line indicates a removable, transportable assembly.

Table 8. Assessment of Sampling System Design 7

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	3	24	May require slops tank for discharge.
Is exposure to high pressure fluids on deck minimized?	8	2	16	Easy to remove/transport, but two cyls.
Is risk to asset minimized?	4	3	12	Adjustable control valve more risky. Discharge to sea undesireable.
Safety/Risk Total	20	8	52	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	5	40	Very controllable.
Does the system provide an isothermal sample?	8	1	8	No obvious temp control.
Does the system prevent hydrates?	4	3	12	Isobaric sample = no dP across system.
Is the system tolerant to slugging?	4	4	16	Includes prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	3	18	Residue still left in lines.
Representative Sample Total	30	16	94	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	4	40	Sense piston position.
Is the system able to confirm the phases present in the sample?	10	4	40	Comb. Of P,T and piston position.
Sample Verification Total	20	8	80	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning
Is the system low in complexity?	2	2	4	Back pressure control, slops tank and addl. Valve and MeOH add complexity.
Is the system easily operated?	3	2	6	Back pressure control and addl valve and MeOH add difficulty.
Is the system easily maintained?	3	4	12	
Can the system take samples at sub-ambient pressure?	3	0	0	No. Requires pump.
Does the system provide the ability to clean/prepare for the next sample?	4	4	16	Ability to flush/clean
Operation Total	20	14	43	
Cost/Weight	10			
Minimum Cost?	3	2	6	Floating pistons are costly. MeOH system.
Minimum Size/Weight?	7	2	14	Floating pistons are heavy. MeOH system.
Cost/Weight Total	10	4	20	
Category Weight Total (Weight Must Total 100)	100	50	289	
Total Allocated to Criteria (Must Total 100)	100			

System 8

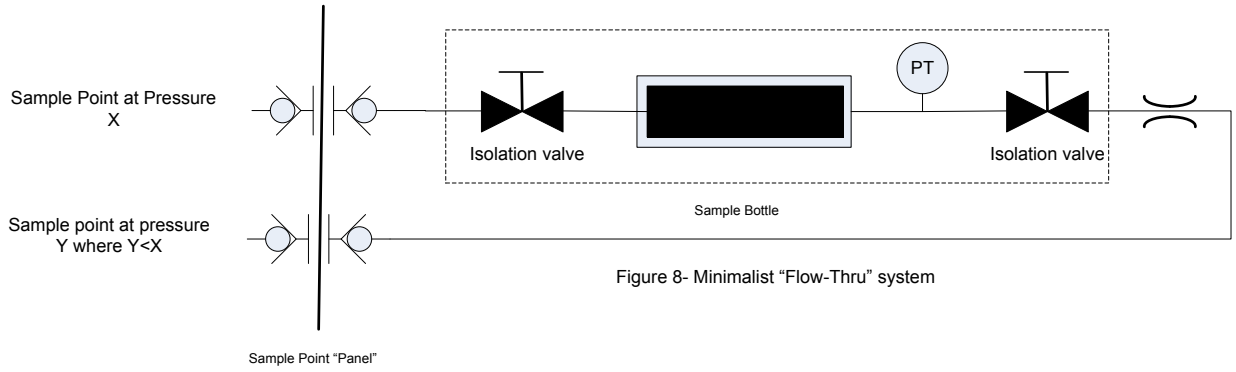

Figure 8- Minimalist "Flow-Thru" system

Definition: The system used to take advantage of pressure differential across the production choke to drive the sample through sample bottle until equilibrium is established. Note: The dashed line indicates a removable, transportable assembly.

Table 9. Assessment of Sampling System Design 8

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	4	32	No slops tank required.
Is exposure to high pressure fluids on deck minimized?	8	3	24	Easy to remove/transport.
Is risk to asset minimized?	4	4	16	Low risk of discharge to sea.
Safety/Risk Total	20	11	72	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	2	16	dp is velocity dependent.
Does the system provide an isothermal sample?	8	4	32	Flow through can heat system.
Does the system prevent hydrates?	4	2	8	Flow limiter could be a problem.
Is the system tolerant to slugging?	4	1	4	Not inherently. Requires prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	4	24	Not likely. Previous sample is flushed.
Representative Sample Total	30	13	84	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	4	40	Constant volume.
Is the system able to confirm the phases present in the sample?	10	1	10	Phase amounts left to chance.
Sample Verification Total	20	5	50	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning.
Is the system low in complexity?	2	4	8	Flow limiter may be a problem.
Is the system easily operated?	3	4	12	
Is the system easily maintained?	3	4	12	
Can the system take samples at sub-ambient pressure?	3	5	15	Yes
Does the system provide the ability to clean/prepare for the next sample?	4	4	16	Flushing is inherent. But total flush may not be acheivable.
Operation Total	20	23	68	
Cost/Weight	10			
Minimum Cost?	3	4	12	Uses constant volume cylinder.
Minimum Size/Weight?	7	4	28	Uses constant volume cylinder.
Cost/Weight Total	10	8	40	
Category Weight Total (Weight Must Total 100)	100	60	314	
Total Allocated to Criteria (Must Total 100)	100			

System 9

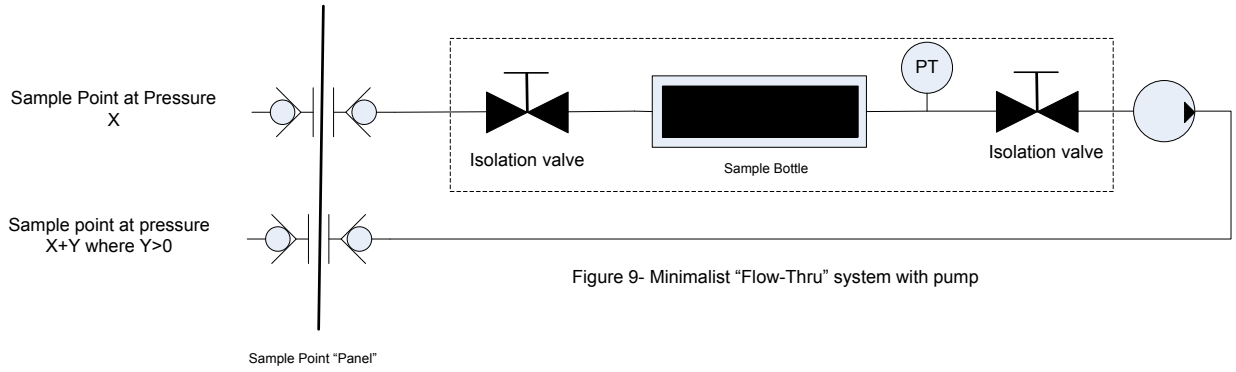

Figure 9- Minimalist "Flow-Thru" system with pump

Definition: This system establishes identical conditions in both the sample bore and the sample bottle. A pump is used to create a pressure differential sufficient to cause flow through the sample cylinder. Note: The dashed line indicates a removable, transportable assembly.

Table 10. Assessment of Sampling System Design 9

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	4	32	No slops tank required.
Is exposure to high pressure fluids on deck minimized?	8	3	24	Easy to remove/transport.
Is risk to asset minimized?	4	3	12	Pump represents increased risk of discharge to sea.
Safety/Risk Total	20	10	68	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	2	16	dp is velocity/pump dependent.
Does the system provide an isothermal sample?	8	4	32	Flow through can heat system.
Does the system prevent hydrates?	4	1	4	Pump could be a problem.
Is the system tolerant to slugging?	4	1	4	Not inherently. Requires prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	4	24	Not likely. Previous sample is flushed.
Representative Sample Total	30	12	80	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	4	40	Constant volume.
Is the system able to confirm the phases present in the sample?	10	1	10	Phase amounts left to chance.
Sample Verification Total	20	5	50	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning.
Is the system low in complexity?	2	3	6	Pump could be a problem
Is the system easily operated?	3	3	9	Pump could be a problem
Is the system easily maintained?	3	3	9	Pump could be a problem
Can the system take samples at sub-ambient pressure?	3	5	15	Yes.
Does the system provide the ability to clean/prepare for the next sample?	4	4	16	Flushing is inherent. But total flush may not be acheivable.
Operation Total	20	20	60	
Cost/Weight	10			
Minimum Cost?	3	3	9	Uses pump.
Minimum Size/Weight?	7	3	21	Uses pump.
Cost/Weight Total	10	6	30	
Category Weight Total (Weight Must Total 100)	100	53	288	
Total Allocated to Criteria (Must Total 100)	100			

System 10

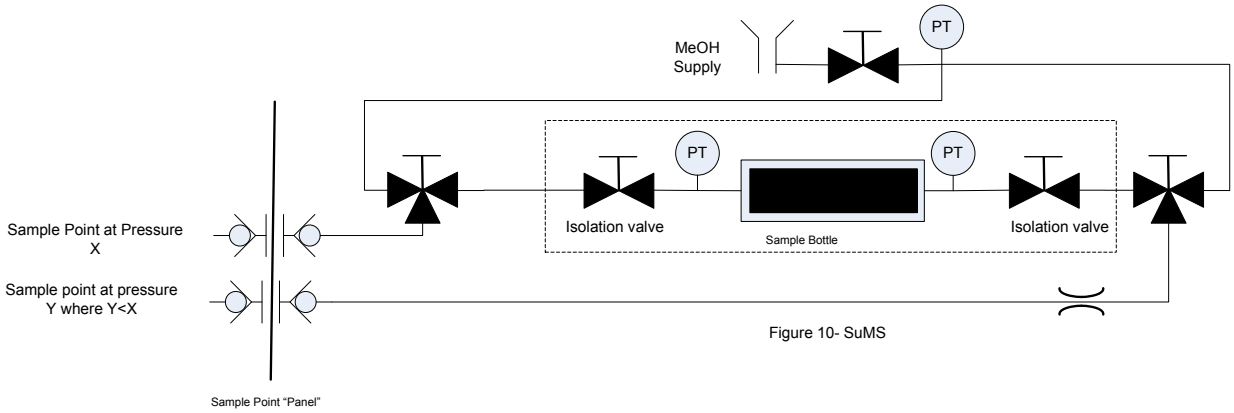

Figure 10- SuMS

Definition: The system is used to take advantage of pressure differential across the production choke to drive a sample through the sample bottle until equilibrium is established. This variant is equipped with a methanol injection line to be used to purge sample lines. Note: The dshed line indicates a removable, transportable assembly.

Table 11. Assessment of Sampling System Design 10

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	4	32	No slops tank required.
Is exposure to high pressure fluids on deck minimized?	8	3	24	Easy to remove/transport.
Is risk to asset minimized?	4	4	16	Low risk of discharge to sea.
Safety/Risk Total	20	11	72	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	2	16	dp is velocity dependent.
Does the system provide an isothermal sample?	8	4	32	Flow through can heat system.
Does the system prevent hydrates?	4	2	8	Flow limiter could be a problem.
Is the system tolerant to slugging?	4	1	4	Not inherently. Requires prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	4	24	Not likely. Previous sample is flushed.
Representative Sample Total	30	13	84	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	4	40	Constant volume.
Is the system able to confirm the phases present in the sample?	10	1	10	Phase amounts left to chance.
Sample Verification Total	20	5	50	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning.
Is the system low in complexity?	2	2	4	More valves/complexity. Flow limiter may be a problem. MeOH more complex.
Is the system easily operated?	3	2	6	More valves, MeOH - more complicated to operate.
Is the system easily maintained?	3	4	12	
Can the system take samples at sub-ambient pressure?	3	5	15	Yes.
Does the system provide the ability to clean/prepare for the next sample?	4	4	16	Flushing is inherent. But total flush may not be acheivable.
Operation Total	20	19	58	
Cost/Weight	10			
Minimum Cost?	3	3	9	MeOH system.
Minimum Size/Weight?	7	3	21	MeOH system.
Cost/Weight Total	10	6	30	
Category Weight Total (Weight Must Total 100)	100	54	294	
Total Allocated to Criteria (Must Total 100)	100			

System 11

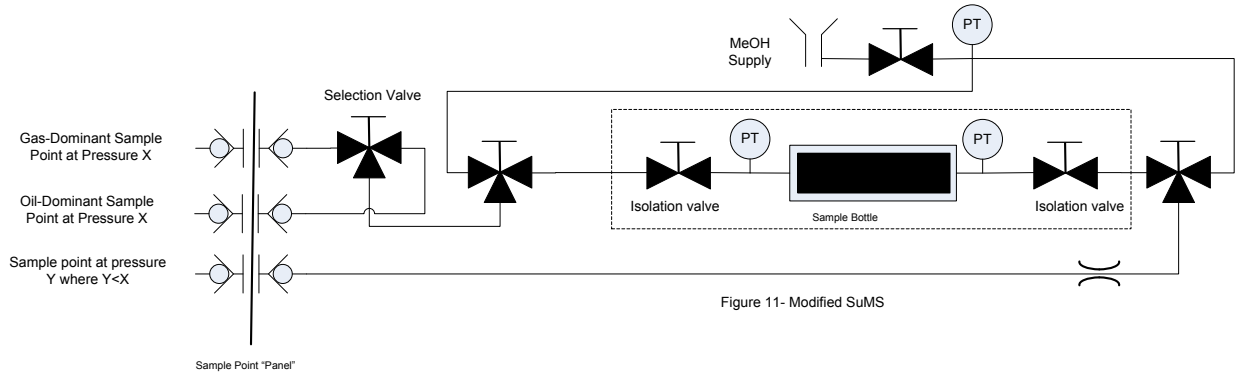

Figure 11- Modified SuMS

Definition: The system takes advantage of pressure differential across the production choke to drive a sample through sample bottle until equilibrium is established. This variant is equipped with a methanol injection line to be used to purge sample lines. There are multiple sampling points that are selectable. The selection valve can be either in the sampling tool or on the panel. Note: The dashed line indicates a removable, transportable assembly.

Table 12. Assessment of Sampling System Design 11

Criterion	Weight	Score	Weighted Score	Comments
Safety/Risk	20			
Will there be extra (non-sampled) hydrocarbons on deck?	8	4	32	No slops tank required.
Is exposure to high pressure fluids on deck minimized?	8	3	24	Easy to remove/transport.
Is risk to asset minimized?	4	4	16	Low risk of discharge to sea.
Safety/Risk Total	20	11	72	
Provides "representative" (previously defined by Task Group) sample.	30			
Does the system provide an isobaric sample?	8	2	16	dp is velocity dependent.
Does the system provide an isothermal sample?	8	4	32	Flow through can heat system.
Does the system prevent hydrates?	4	2	8	Flow limiter could be a problem.
Is the system tolerant to slugging?	4	1	4	Not inherently. Requires prudent sample point selection.
Does the system provide a sample that is free of contaminants?	6	4	24	Previous sample is flushed.
Representative Sample Total	30	13	84	
Sample Verification	20			
Is the system able to confirm the amount of sample acquired?	10	4	40	Constant volume.
Is the system able to confirm the phases present in the sample?	10	3	30	Prudent sample point selection. But single cylinder for oil sample and gas sample seems risky. Still hard to tell how much of each phase.
Sample Verification Total	20	7	70	
Operation	20			
Can the system take multiple samples from a single connection/sample point?	4	1	4	System must be disconnected and replaced.
Does the system take advantage of preconditioning?	1	1	1	No preconditioning.
Is the system low in complexity?	2	2	4	More valves/complexity. Flow limiter may be a problem. MeOH more complex.
Is the system easily operated?	3	2	6	More valves, MeOH - more complicated to operate.
Is the system easily maintained?	3	4	12	
Can the system take samples at sub-ambient pressure?	3	5	15	Yes
Does the system provide the ability to clean/prepare for the next sample?	4	5	20	Flushing is inherent. Addl cleaning via MeOH.
Operation Total	20	20	62	
Cost/Weight	10			
Minimum Cost?	3	3	9	MeOH system.
Minimum Size/Weight?	7	3	21	MeOH system.
Cost/Weight Total	10	6	30	
Category Weight Total (Weight Must Total 100)	100	57	318	
Total Allocated to Criteria (Must Total 100)	100			

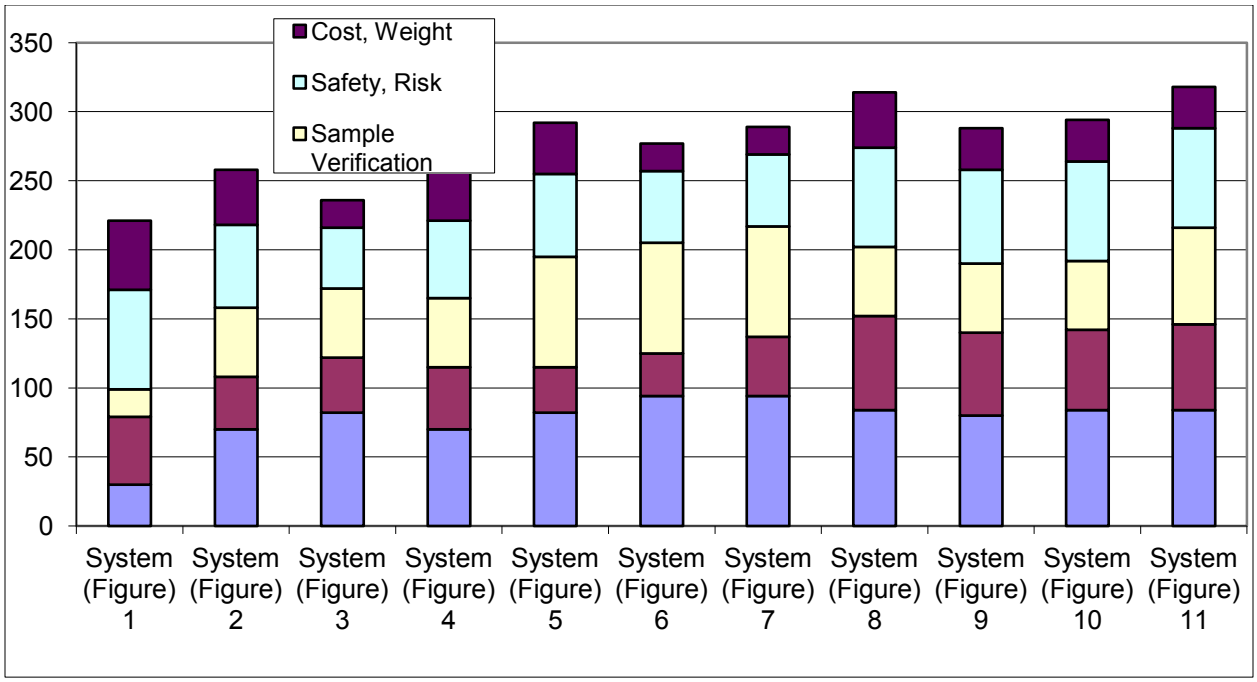

Figure 14. Numerical Assessments of Design Options

Appendix C: Subsea Fluid Sampling Best Practices Guideline

Following is a white paper intended to provide the basis for a sampling best practices guideline. The main issues in subsea sampling are identified. Where it exists, information has been included. In other instances, a "place-holder" identifies the need for addition of information at a later date.

1 INTRODUCTION

The increase in deepwater production in the Gulf of Mexico and other locations around the world has brought a corresponding increase in the use of subsea multiphase flowmeters. The placement of subsea multiphase flowmeters near the well provides improved reservoir management, well diagnostics, and allocation. However, multiphase flowmeters require timely, accurate fluid properties, at meter conditions, to realize their full potential. Subsea architectures with long flow lines and risers have led to the realization that well tests and topside samples cannot meet the needs of this new measurement technology. Sampling at or near the wellhead can provide samples representative of the fluid flowing through the meter, yielding more accurate fluid properties and more accurate multiphase measurements.

Traditionally, samples are taken from a topside separator. An individual well is isolated, the flowline/riser is flushed with the test well's flow, and the sample is taken when the isolated well stream makes it to the topside separator. When the subsea architecture includes long subsea tiebacks, this process becomes more difficult. This process is problematic for several reasons: 1) shutting-in wells results in costly deferred production, 2) samples may not be representative due to thermodynamic and hydrodynamic changes as the fluid moves through the long flowline/riser combination, and 3) flow assurance concerns (hydrates, wax, asphaltenes) may prohibit this type of sampling altogether.

Multiphase flow meters require accurate fluid properties, such as gas, oil and water density, water conductivity, oil permittivity and mass attenuation for accurate flow measurement. These properties may change throughout the life of the well, reducing the accuracy of the meter. Periodic in situ sampling of the fluid flowing through the meter will improve meter accuracy, thereby improving the allocation process, reservoir management and well diagnostic capability.

The need for subsea sampling is not confined to multiphase meters. Other applications that would benefit from subsea sampling include: determination of gas heating value, API Gravity, sulphur content and other fluid properties and quality parameters, detection of contaminants, and regulatory issues, such as when the governing regulatory authority asks for evidence that compositional information provided by the operator in his application is still the case.

This guideline stems from background research done during RPSEA project 07121-1301 intended to develop a subsea multiphase sampling system.

1.1 Use With Other Documents

It is intended that this guideline be used in conjunction with other similar documents to guide the user toward sound measurement practice in upstream hydrocarbon production applications. Specifically this document will address in depth the question of how the user obtains samples of oil, gas, water, and other fluids that are present in the effluent stream of a single well. This requires the definition not only of the methodology which is to be employed, but also the provision of evidence that this methodology will produce a "representative" fluid sample in the intended environment.

2 SCOPE

This document provides design and operating guidance for sample collection, sample handling, and sample system design. It applies specifically to obtaining subsea fluid samples to support multiphase metering of production fluids. It is based on research as well as practical knowledge from operating companies. While this document does not specifically address collecting samples for detailed PVT analysis (including phase proportions), much of the information can be used for general production fluid sampling.

This guideline was developed giving consideration to offshore installations. These installations generally have minimal laboratory equipment on site and perform sample collection and handling with multi-skilled operations personnel as opposed to laboratory chemists. The techniques described, however, are also applicable to onshore locations.

This guideline may involve hazardous materials, operations, and equipment. This recommended practice does not purport to address all of the safety issues associated with its use. It is the responsibility of the user of this recommended practice to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to use.

3 REFERENCED PUBLICATIONS

1. API RP 85 - Use of Subsea Wet-Gas Flowmeters in Allocation Measurement Systems
2. API RP 86 - Recommended Practice for Measurement of Multiphase Flow
3. API RP 87 - API Recommended Practice for Sampling and Analysis of Crude Oil Streams Containing from Two to Fifty Percent Water by Volume
4. API MPMS 8.2 (ASTM D4177), Automatic Sampling of Petroleum and Petroleum Products
5. API MPMS 20.1, Allocation Measurement
6. NFOGM Handbook of Multiphase Flow Metering`

4 DEFINITIONS AND NOMENCLATURE

4.1. Definitions

Actual conditions: The actual or operating conditions (pressure and temperature) at which fluid properties or volumetric flow rates are expressed.

Allocation: The (mathematical) process of assigning portions of a commingled production stream to the sources, typically wells, leases, units, or production facilities, which contributed to the total flow through a custody transfer or allocation measurement point.

Commingle: To combine the hydrocarbon streams from two or more wells, units, leases, or production facilities into common vessels or pipelines.

Conductivity: The ability of a substance to conduct an electric current. Conductivity is a good measure of salinity in water.

Custody transfer: Measurement of high accuracy where custody of a product is transferred from supplier/deliverer to the shipper/receiver, normally accompanied by a financial transaction based on this measurement.

Density: The mass per unit volume of a substance. Multiphase meters require the densities of the phases as an input.

Emulsion: Colloidal mixture of two immiscible fluids, one being dispersed in the other in the form of fine droplets.

Equations of state (EOS): Equations which relate the compositions, pressures, temperatures, and various other physical properties of gases and liquids to one another, and are used to predict the transformation of physical state when conditions change.

Flow regime: The physical geometry exhibited by a multiphase flow in a conduit; the geometric distribution in space and time of the individual phase components, i.e., oil, gas, water, any injected chemicals, etc. For example, liquid occupying the bottom of a horizontal conduit with the gas phase flowing above.

Fluid: A substance readily assuming the shape of the container in which it is placed; e.g., oil, gas, water, or mixtures of any of these.

Full separation: The separation of fluids in a production stream in which the resulting streams are not multiphase, i.e., there are no liquids in the gas stream nor gas in the liquid stream and oil and water are completely separated from one another.

Gas-liquid ratio (GLR): The ratio of gas volumetric flow rate to the total liquid volumetric flow rate at any point, expressed at standard conditions, usually in standard cubic feet per barrel (SCF/BBL) or standard cubic meters of gas per cubic meter of total liquid (m^3/ m^3).

Gas-oil ratio (GOR): The ratio of gas volumetric flow rate to the liquid hydrocarbon volumetric flow rate at any point, expressed at standard conditions, usually in standard cubic feet per barrel (SCF/BBL) or standard cubic meters of gas per cubic meter of liquid hydrocarbon (m^3/ m^3).

Gas volume fraction (GVF): The fraction of the total volumetric flow at actual conditions in the pipe which is attributable to gas flow, normally expressed as a percentage.

Hold-up: The cross-sectional area locally occupied by one of the phases of a multiphase flow, relative to the cross-sectional area of the conduit at the same local position.

Liquid volume fraction (LVF): The fraction of the total volumetric flow at actual conditions in the pipe which is attributable to liquid flow, normally expressed as a percentage.

Mass attenuation: Basic quantity used in calculations of penetration energy deposition by photons. In multiphase flow meters, attenuation varies depending on the fractions of gas, water, and oil in the flow.

Multiphase flow: Flow of a composite fluid which includes natural gas, hydrocarbon liquids, water, and injected fluids, or any combination of these.

Oil-continuous multiphase flow: Multiphase flow in which the water and any other liquids present are distributed as droplets surrounded by liquid hydrocarbons (oil). Electrically the liquid mixture acts as an insulator, except in certain special cases involving heavy crudes.

Partial separation: The separation of production fluids resulting in streams that are likely to be multiphase, i.e., wet gas and gassy liquid streams.

Permittivity: Related to a material's ability to transmit (or "permit") an electric field. Used to measure the aqueous phase of a multiphase flow.

Phase: A term used in the sense of one constituent in a mixture of several. In particular, the term refers to oil, gas, water, or any other constituent in a mixture of any number of these.

Phase mass fraction: The mass flow rate of one of the phases of a multiphase flow, relative to the total multiphase mass flow rate.

Phase volume fraction: The volumetric flow rate of one of the phases of a multiphase flow, relative to the total multiphase volumetric flow rate.

Pressure-volume-temperature (PVT) relationship: Application of Equations of State (EOS) to a composite fluid to calculate the change in properties in going from one set of conditions (P and T) to another.

Repeatability: The closeness of the agreement between the results of successive measurements of the same measurand carried out under the same conditions of measurement. Related to precision.

Representative sample: A sample containing each of the phases present at the meter, in which each phase has the same composition as those at the meter. Note that this is different from a "fractionally proportional" sample, since there is no need to determine the amount of each phases in the sample.

Reproducibility of results of measurements: The closeness of the agreement between the results of measurements of the same measurand carried out under changed conditions of measurement, such as different location, time, reference standard, etc. [Ref. 6, B.2.16]

Salinity: A measure of the mass of dissolved salts in the water phase, usually expressed as parts per thousand (ppt).

Slip: Condition that exists when the phases have different velocities at a cross-section of a conduit.

Slip ratio: A means of quantitatively expressing slip as the phase velocity ratio between the phases.

Slip velocity: The phase velocity difference between two phases.

Standard conditions: A set of standard (or reference) conditions, in terms of pressure and temperature, at which fluid properties or volumetric flow rates are expressed.

Surface tension: a property of the surface of a liquid that allows it to resist an external force. This property is responsible for many of the behaviors of liquids.

Verification: The process of confirming the accuracy of an instrument by comparing its output to that of a Measurement Standard, a Reference Standard, or to the value of a Reference Material.

Viscosity: A fluid's resistance to shear stress.

Watercut (WC): The water volumetric flow rate, relative to the total liquid volumetric flow rate (oil and water), both converted to volumes at standard pressure and temperature. The WC is normally expressed as a percentage.

Water-liquid ratio (WLR): The water volumetric flow rate, relative to the total liquid volumetric flow rate (oil and water), at the pressure and temperature prevailing in that section.

Wet gas: A particular form of multiphase flow in which the dominant fluid is gas and in which there is a presence of free-flowing liquid.

4.2. Symbols and Abbreviations

Symbol	Meaning
±	plus or minus
ρ	“rho” stands for density
°C	degrees Celsius
°F	degrees Fahrenheit
°API	degrees API gravity
[abs.]	Absolute; meaning absolute error

cP	centipoises
ft/s	Feet per second
g	grams
mL	milliliter
m/s	meter/second
psi	pounds per square inch (pressure)
[rel.]	Relative; meaning relative error
RPM	revolution per minute
S&W	sediment and water
V	volume
A	cross-sectional area, or fractional cross-sectional area occupied by either gas or liquid
BOPD	Barrels of Oil per day
EOS	Equation(s) of State
GOR	Gas-Oil Ratio
GLR	Gas-Liquid Ratio
GVF	Gas Volume Fraction
LVF	Liquid Volume Fraction
MPFM	Multiphase Flow Meter
P, T	Pressure and Temperature
Ps, Ts	Pressure and Temperature at Standard (Reference) Conditions
psi	Pounds Per Square Inch
PVT	Pressure-Volume-Temperature
ρg	Gas Density
ρl	Liquid Density
V	Velocity of Liquid or Gas in a Pipe
WC	Watercut
WLR	Water-Liquid Ratio

4.3 Abbreviated Terms

API	American Petroleum Institute
ASTM	American Society for Testing and Materials
MMS	US Minerals Management Service
MPMS	Manual of Petroleum Measurement Standards
NEL	National Engineering Laboratory
NFOGM	Norwegian Society for Oil and Gas Measurement
ISO	International Standards Organization

5 INTRODUCTION

5.1 General

Multiphase flow meters require accurate fluid properties, such as gas, oil, and water density, water conductivity, oil permittivity, and mass attenuation for accurate flow measurement. These properties change throughout the life of the well, reducing the accuracy of the meter. Periodic *in situ* sampling of the fluid flowing through the meter will improve meter accuracy, thereby improving the allocation process, reservoir management, and well diagnostic capability.

5.2 Multiphase Flow

A basic primer on multiphase flow. Borrow from known standards. Include in REFERENCED PUBLICATIONS

5.3 Multiphase Flow Meters

A basic primer on multiphase flow meters. Emphasize fluid properties required by the various meters. Borrow from known standards. Include in REFERENCED PUBLICATIONS.

Results from Survey of Manufacturers conducted in late 2008

In late 2008, in preparation for the RPSEA 07121-1301 Subsea Sampling Task, three multiphase meter manufacturers were asked to respond to a survey. The survey was intended to clearly identify the fluid property inputs required and best practices for optimizing meter accuracy. Their responses are below. These should be revisited as this document develops.

Roxar

Questions:

Specifically for a subsea project, if a live multiphase fluid sample was collected and made available by the operator, what fluid and bulk fluid properties would Roxar like to obtain from it in order to provide optimal meter performance? Please list ALL data that you would request from the fluid laboratory.

Our current understanding for your meter is listed below, if you could also confirm and/or correct this understanding it would be greatly appreciated.

1. Please confirm that PVT data is required, including shrink and flash factors to convert flow rate from flowing conditions to standard conditions.

2. Please confirm that you require the Permittivity of the oil? Can oil permittivity be estimated using API of the oil? If so, what is the range of API gravities where this correlation is valid?

3. If we want to measure the oil permittivity, does the wavelength used to measure permittivity affect the measurements? Does Roxar have a recommended wavelength of the measuring instrument to obtain oil permittivity?

4. Please confirm that you require the Conductivity of water.

5. Please advise if there are any other fluid needs for your meter.

6. Further, what other fluid information in the future might allow further improved performance?

Response:

1. Please give us all the information and we will generate the PVT tables. Please also send us the report on the analysis.

2. Yes we require the permittivity of the oil, there are converters that will give density from API, we can then find the permittivity.

3. Normally the frequencies used on hydrocarbons will not affect the result.

4. Yes we require the Conductivity of water.

5. No

6. When the well is getting higher watercut, then you might want to adjust the conductivity input.

The following information is required for the MPFM to calculate the corrected flow rates to standard conditions:

Petroleum composition in mole% (alt. wt%)
Composition of fluid passing through the meter (monophasic fluid Composition, reservoir fluid Composition, BHS).
MPFM working range (P and T)
Reference conditions (P and T)
Water salinity in ppm
Density of plus fraction

Other Requirements(if available):

The conductivity of the produced water
The Downstream Flowing Pressure
The Downstream Flowing Temperature
Permittivity of the oil

Example of PVT data analysis to be filled in (the molecular composition of reservoir fluid):

Component	**Formula**
Nitrogen	N
Carbon Dioxide	CO2
Hydrogen Sulphide	H2S
Methane	C1
Ethane	C2
Propane	C3
I-Butane	iC4
N-Butane	nC4
I-Pentane	1C5
N-Pentane	nC5
Hexanes	C6
Septanes	C7
Octanes	C8
Nonanes	C9
Decanes	C10
Undecanes	C11

Dodecanes	C12
Tridecanes	C13
Tetradecanes	C14
Pentadecanes	C15
Hexadecanes	C16
Heptadecanes	C17
Octadecanes	C18
Nonadecanes	C19
Eicosanes	C20+

MPM

*Questions*Specifically for a subsea project, if a live multiphase fluid sample was collected and made available by the operator, what fluid and bulk fluid properties would MPM like to obtain from it in order to provide optimal meter performance ? Please list ALL data that you would request from the fluid laboratory.

Our current understanding for your meter is listed below, if you could also confirm and/or correct this understanding it would be greatly appreciated.

1. Please confirm that PVT data is required, including shrink and flash, to convert flow rate from flowing conditions to standard conditions.

2. Please confirm the meter uses a correlation of API gravity to determine the dielectric constant of the oil? If so, please validate the range of API where this correlation is valid.

3. Please confirm the meter has a conductivity probe which measures salinity of the water. Would additional water property information from a sample be of additional benefit?

4. Please confirm a gamma source is used to measure total density. What fluid properties are required by this gamma system to interpret attenuation into density?

5. Please confirm that the 3D system requires the fluid dielectric for each phase, and how this is obtained ? Would additional dielectric properties of each phase from a sample be of additional benefit?

6. Please advise if there there any other fluid needs for your meter?

7. Further, what other fluid information in the future might allow further improved performance?

Response

The MPM meter has been designed for applications where post-installation sampling is not practical. The built-in water salinity measurement system, self diagnostics and in-situ verification system automatically compensate for variations in fluid properties throughout the field life. A sampling system is therefore not required for the MPM meter. Data required prior to (or during) start-up is a complete fluid composition analysis, or alternatively pressure, temperature, density, surface tension tables for oil and gas.

1. A complete fluid composition analysis is required to configure the MPM meter. We use Calsep PVTSim Open Structure as PVT engine. This PVT engine performs flash calculations in order to calculate look-up tables for oil and gas density, viscosity and surface tension at actual conditions, which is downloaded to the MPM meter. Quite substantial changes to the fluid properties and densities can occur, without this having a significant impact on the measurement uncertainties.

2. Rather than API gravity, the MPM meter use density to determine the dielectric constant of the oil. This has been validated for a large variety of condensate and crude oil samples (500 to 900 kg/m3).

3. Confirmed – the MPM meter has a built-in salinity/conductivity probe for auto calibration of changes in salinity in the flowing fluid. Additional water property information from a sample would be beneficial to verify the performance of the conductivity probe, but would not improve the salinity determination.

4. A gamma meter is used to measure the mixture mass attenuation in the center of the pipe section (the gamma densitometer does not give accurate total density, as the mixture is generally not homogeneous). This mass attenuation is used in combination with the 3D system to determine phase rates.

Fluid properties required by the gamma system are individual mass attenuation coefficients for each of the oil, gas and water phases. The individual mass attenuation coefficients can be calculated from the individual phase densities

(from fluid composition analysis), or entered manually if known. It is important to note that the densities – and hence the individual mass attenuation coefficients – are automatically configured based on the salinity measurements and self diagnostics system of the MPM meter. Also, high energy is less affected by variance in components like H_2S, etc, when compared to lower energy sources.

5. Confirmed – the dielectric properties for each of the phases (oil, gas, water) are required for the MPM meter. The dielectric properties are calculated based on the fluid composition analysis and densities, or can be entered manually if known. The dielectric properties are constantly verified through the in-situ verification system, and are adjusted if needed. Other than for additional verification, fluid samples will not improve the performance of the MPM meter.

6. Other than what has been mentioned above, no additional fluid properties are needed.

7. It may be beneficial to be able to flush the MPM meter with MEG or Methanol to obtain a single point "finger print" verification of the calibration of the meter. It is not expected that this is beneficially performed more frequently than once every five years.

Framo/Schlumberger

Questions

Specifically for a subsea project, if a live multiphase fluid sample was collected and made available by the operator, what fluid and bulk fluid properties would Framo like to obtain from it in order to provide optimal meter performance ? Please list ALL data that you would request from the fluid laboratory.

Our current understanding for your meter is listed below, if you could also confirm and/or correct this understanding it would be greatly appreciated.

1. Please confirm that PVT data is required, including shrink and flash, to convert flow rate from flowing conditions to standard conditions.

2. Please confirm the meter requires linear attenuations for each phase at two energy levels.

3. Please confirm the meter requires density correlations for each phase.

4. Please confirm the meter requires viscosity correlations for each liquid phase.

5. Please advise if there there any other fluid needs for your meter?

6. Further, what other fluid information in the future might allow further improved performance?

Response

1. There are two options, either to setup the Vx with a generic black oil model (BOM) or a with Fluids ID (FID). The BOM requires as input oil density at standard conditions, oil viscosity at standard conditions, water density at standard conditions, gas specific gravity and gas composition to C_9+.

For a FID setup we require a reservoir fluid composition, saturation pressure and temperature and oil density at standard conditions. This information is usually found in a standard PVT report. We can also make use of additional information in the PVT report to possibly enhance the FID setup. From the required information we will generate the PVT data needed to be input to the Vx. The client might also provide the PVT data directly in a specified format. The data needed then are tables for oil, water and gas densities. Oil viscosity. Oil, water and gas formation volume factors. Gas phase condensate ratio, rgmp. Stock tank gas oil ratio, R_{st}. Stock tank gas water ratio, R_{wst}. Among these varibles, it is the oil, water and gas densities that are required to provide oil, water and gas rates at line conditions. The additional variables listed above are required to convert from line to standard conditions.

2. The linear attenuations required can be found by in-situ measurements on oil and water samples. Sometimes it is feasible to do in-situ on gas, but not always. The linear attenuations can also be calculated based on compositional data of the oil and gas. The water attenuations can be found from a water chemistry analysis.

3. From a reservoir fluid composition (see 1.) we can calculate the oil, water and gas correlations needed as input. The client might also provide tabulated data of oil, water and gas properties from which we can generate the correlations which is required as input to the Vx. If the Vx is setup with a BOM (see 1.) the density information is provided in the pre-installed BOM in the Vx.

4. In practice, only the oil viscosity is required. However, the viscosity influence on the measurements will depend on how viscous the oil is. Thus, the importance of the viscosity input might be relaxed for low viscous oils.

5. The requirements listed above should cover the input requirements.

6. The more you know about your fluids the better. However, we do not foresee that more input is required than listed above. For special applications, special requirements on fluid properties might emerge, e.g., ultra-viscous oil, oil production with the assistance of steam injection, etc.

5.5 Measurement Uncertainty

A basic primer on measurement uncertainty. Borrow from known standards. Include in REFERENCED PUBLICATIONS

6 CONSIDERATIONS FOR MULTIPHASE FLUID SAMPLING

6.1 General

All multi-phase meters (MPFMs) require input of fluid properties to measure the flow rate of gas, oil and water. All MPFMs use two types of fluid property inputs:

1. Phase behavior such as density, formation volume factor, gas-oil ratio at the flowing conditions of the MPFM
2. Vendor specific fluids information such as one of the below:
    a. Permittivity of the oil
    b. Mass attenuation of the oil and water
    c. Conductivity of the produced water

A sample collected at the wellhead for each well before it is commingled with other production subsea is the most suitable sample for analysis and its measured properties input in the MPFM.

7 OBTAINING FLUID SAMPLES SUBSEA

7.1 Thermodynamic and Fluid Mechanics Considerations

- Thermodynamics - Phase Equilibrium, Joule-Thomson effect.
- Fluid Mechanics - Turbulence, phase mixing, phase separation, phase inversion.
- Hydrates, Wax, Asphaltenes

7.2 Sampled Fluids

- Water (Importance of accurate water cut)
- Oil
- Gas
- Others

7.3 Fluid Properties

7.4 Sample Point Location

Consolidation of sample point location studies under multiphase flow conditions. The following summarizes results from RPSEA sample point location tests performed by Letton-Hall Group at Southwest Research Institute. This was a "quick-look" series of tests intended to provide guidance for future studies. Very little public information about sampling under multiphase flow conditions exists.

Liquid-Dominant Sample Point:

- Very high water content (almost no oil) collected from liquid-dominant port.
    - » Likely due to stratified flow in horizontal section upstream of sampling tee – water on bottom, oil above.
- Approximately 60% water/40% oil collected from reference port.

    - » Surprising because mixing downstream of blind tee should have produced 2% water in the sample. Would not expect holdup.
    - » Sample port is in center of pipe.
    - » But, from a sampling (for MPFMs) standpoint, it's a good sample.

Gas Dominant Sample Point:

- Insufficient amount of liquid collected from gas-dominant sample port and from reference sample port.
    - » Low dp across sampling system suggests insufficient time to accumulate sample.
        - Over 45 minutes elapsed before aborting sample from gas-dominant port.
        - 20 minutes elapsed before aborting sample from reference port.
- 100 cc of gas collected from liquid-dominant sample port in approximately 7 minutes.

7.5 Maintaining Sample Integrity

- Design considerations for sample systems and sample lines.
- Level of instrumentation required to have confidence in sampling.
- As technology develops it should be incorporated into the system.
- Handling/care of the sample.
- P and T recording.

7.6 Sample Handling and Analysis After Collection

A sample collected at the wellhead for each well before it is commingled with other production subsea is the most suitable sample for analysis and its measured properties input in the MPFM. The multi-phase sample collected at the wellhead should be managed such that its pressure and temperature during sample collection is very close to the flowing pressure and temperature at the MPFM. This facilitates the assumption that the gas and liquids collected are representative (with respect to their properties) of the fluids flowing through the MPFM (not necessarily with respect to the fractions of each phase). The subsea sample with some fraction of gas, oil, and produced water is retrieved and the following steps and analyses are recommended:

1. Stabilize the sample cylinder at the sampling pressure and temperature
2. Separate the gas, oil, and produced water isothermally and isobarically from the sample cylinder. Because of this step, it is preferred to collect the samples in a piston cylinder.
3. Stabilize the gas at sampling conditions and use an aliquot to conduct the following analyses:
    a. Flash the gas from sampling conditions to ambient conditions and measure gas-oil ratio (GOR). Typically, the gas is dry and would not yield any condensate.
    b. Measure the composition of the separated gas and condensate (if any) using gas chromatography in the laboratory.
    c. Conduct QC of the results using Hoffman-Crump or similar K-value method (if any condensate was recovered).
4. Stabilize the oil at sampling conditions and use an aliquot to conduct the following analyses:
    a. Measure the bubble point pressure at sampling temperature and ensure that it is close to the sampling pressure. If not, the sample may be invalid.
    b. Flash the oil from sampling conditions to ambient conditions and measure gas-oil ratio (GOR), API gravity and composition of the oil using gas chromatography in the laboratory. Also, measure formation volume factor and density at sampling conditions.
    c. Conduct QC of the results using Hoffman-Crump or similar K-value method (if any condensate was recovered).
    d. Measure one of the following as dictated by the MPFM vendors:
        i. Oil permittivity for single energy gamma MPFMs
        ii. Mass attenuation of oil for dual energy gamma MPFMs
5. The water separated from the multiphase sample needs to be analyzed for
    a. Specific gravity of water

b. Total dissolved solids and one of the following measurements based on the MPFM vendor:
    i. Conductivity of water for single energy gamma MPFMs (some don't need it)
    ii. Mass attenuation of water for dual energy gamma MPFMs

6. QC the separated gas (from Step 3) and oil compositions (from Step 4) at flowing conditions using K-values.
7. Based on the information obtained so far, equation of state (EOS) models can be built, and fluid properties predicted by the tuned EOS model can be entered in the MPFM for further use.

8 INITIATING A SUBSEA SAMPLING CAMPAIGN

8.1 General

Identify the general issues surrounding a sampling campaign, such as when, why, and how extensive a sampling campaign should be. Discuss "flags" that should trigger a sampling campaign:

- Changes in fluid properties, such as density.
- Water breakthrough.
- Changes of zones in multi-zone completion.
- Others,

8.2 Company Requirements

8.3 Meter Requirements

- Discuss types of meters and the information they require.
- Discuss which fluid properties are required and why.

8.4 Laboratory Requirements

- Overview of laboratories, analyses and analytical equipment.
    - Laboratory requirements.
    - Discuss amount of samples needed.
    - Discuss types of analyses and the samples required for each type of analysis.
- Discuss transport vessels and DOT rating.
- Discuss sampling frequency (when density changes, when water breaks through, changes of zones in multi-zone completion.
- List the "flags" that should trigger a sampling "campaign."
- Discuss safety and DOT rated transport vessels.
- Depends on type of meter being used.

9 UNIVERSAL SAMPLING INTERFACE

9.1 General

Emphasize the use of the interface to allow manufacturers to focus on the sampling system and to provide users with the flexibility of trying sampling systems from various manufacturers that couple to the interface.

9.2 Description, Drawings and Bill of Materials.

10 BIBLIOGRAPHY

11 APPENDICES

12 LIST OF FIGURES

13 LIST OF TABLES

RPSEA

ROV-Assisted Subsea Measurement Final Report

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Improvements to Deepwater Subsea Measurement

07121-1301

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Abstract

This report documents a project to improve subsea flow measurements to allow the flow rates of individual wells to be known more accurately, thus reducing risk to both producers and the US government while also improving reservoir recovery. In this project, a non-invasive metering approach was adopted using a clamp-on meter that may be conveyed to the sea floor using a ROV. The goal of this project was to develop and prove methods for conveying a clamp-on meter to the sea floor by ROV, and document the results as a draft standard for the future. Meters/sensors were marinized for prototype demonstration in surface multiphase flow loops and in underwater test tanks.

Prepared by:	Approved by:
Eric Toskey (LHG)	
	Date: September 20, 2011

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1. Introduction

This paper presents the world's first subsea ROV-assisted clamp-on measurement solution, and the industry factors and needs that have shaped its development. ROV-assisted measurement is the process of using an ROV in deep water to pick up a meter deployed to the seabed from surface, flying it to a metering location, installing it on the pipe. After installation, measurements are made on the fluids flowing in the pipe, and the data is sent to the surface in real-time via the ROV umbilical. The meter can be flown to and installed at several metering locations before it is retrieved to the surface. The process of developing the technology is reviewed and the prototype meter that was fabricated and tested is presented. The work presented here is the result of Task 2 of the RPSEA DW1301 project, Improvements to Deep Water Subsea Measurement, which has been presented in overview previously.[1,2,3]

1.1 Flow meter Verification

All flow meters require some form of verification. Most conventional single-phase flow measurements are verifiable because they are well-understood measurements and they are accessible. For land-based or top-side flow meters, verification can be done by:

- Examining the condition of the flow meter itself,
- Examining the condition of the secondary devices and/or the quality of those measurements
- Checking the factory calibration or and re-calibrating the meter if necessary
- Verifying the flow rate determination by checking the calculations using the equations programmed into the meter.

Some meters offer diagnostic software to assist in evaluating the measurement quality and determining the need for re-calibration.

For meters employed in production allocation measurement, another common approach used to verify measurements is to compare the sum of individual flow stream measurements to the measurement of the combined stream. This approach, however, does

not pinpoint measurement problems to the meter, and is affected by other sources of error in rate determination when the flows are metered periodically instead of continuously.

In contrast to conventional single-phase meters, multiphase flow meters are at present less well known, less verifiable, and operating in the much more complex environment of multi-phase flow. One immediate challenge to verifying multiphase flow meters is the complexity of the flow rate algorithms, and their confidentiality. These remain private, non-public information. The challenge is that, even if one can verify the raw measurements, it requires deep, detailed knowledge of the flow measurement technology to verify the flow rate determination is sufficiently accurate. This direct approach to verifying the measurement is complicated and impractical. Moreover, due to the relative inaccessibility of subsea meters, the primary and secondary devices are not verified as any topside or land installed meter.

1.2 Project Motivation-Subsea Multiphase Flow Meter Verification

Subsea flow measurements present some unique problems. A deepwater flow meter is difficult to visually inspect, is difficult to replace in the event of failure, and has fluids flowing through it which may form wax, scale or other coatings. In addition, a meter may be subjected to erosion due to sand flow through it. It is also possible that the fluid properties flowing through a meter may change over the life of the well. Multiphase flow meters installed subsea have no means for in-situ verification. Although it is common practice to verify a multiphase flow meter in a flow loop facility prior to its installation subsea, no further verifications can be made after installation. Either on a regular basis over the life of the meter or when measurement questions arise, there needs to be a method to verify subsea meters.

The need for in-situ verification of an installed multiphase flow meter is what drove the development of an ROV-assisted subsea measurement. Due to the challenges of a direct verification approach, it was decided to develop an indirect approach by deploying a second measurement device which could be used to make a comparative analysis to evaluate or verify measurements made in a subsea field. The installation of the second measurement device would be temporary and suitable for periodic or event-based verification. An

advantage of deploying a second measurement is that the condition of the second measuring device is known and verified, whereas the condition of the installed meter may be suspect. The ROV was chosen as a means for deployment due to its common use in the deep water, subsea environment for similar work at wellheads and other seabed installed infrastructure.

There are other needs for ROV-conveyed measurement besides the verification of existing meters, such as in a deep water production gathering network where measurement is needed, is not present, and for which no practical work-around solution can be used to provide it. Another need would be to reduce well test time and avoid the deferral of production where wells can only be tested by difference or shutting in companion wells that share a long tieback flow line. In this case, the ROV-conveyed measurement can provide the allocation of flow between the commingled wells without changing the producing conditions. The advent of subsea processing provides numerous additional opportunities in which it will become necessary to provide short-term – or maybe long-term – measurement other than that which was incorporated in the original subsea infrastructure. Certainly there will be other applications not yet imagined, as the frontier nature of deepwater technology continues to evolve. However, we believe that ROV-conveyance has the potential to be the vanguard method of deployment for subsea metering in the foreseeable future.

2. Organization

An important aspect of the execution of this task was the creation of a team to execute the plan. The team members were:

- Philippe Remacle (Total), initially, and Moussa Kane (Total), secondly, served as Task Champion. M. Kane replaced P. Remacle approximately halfway through the task. In this role, P. Remacle and M. Kane served as the lead technical coordinator for the JIP members for all interaction with the task manager and subcontractors.
- Eric Toskey (Letton-Hall Group) was the overall manager of the task effort.
- Chip Letton (Letton-Hall Group) served as a special technical advisor to the task.
- Task Working Group. JIP members who have special interest in the Task technology or application. : BHP Billiton, BP, ConocoPhillips, Chevron, Shell, Statoil, and Total
- Subcontractors.
    - Oceaneering International, Inc. (OII) had responsibility for repackaging of the Neftemer meter components and the design of all other components for subsea deployment (marinization) of the meter. Oceaneering also supplied the facilities, equipment and personnel for manufacturing and assembly and functionality testing of the meter, as well as the underwater testing in a tank with an ROV.
    - Southwest Research Institute (SwRI) had responsibility for supporting the evaluation of the RPSEA Task 2 prototype through-pipe measurement system on a 3-phase flow of oil/water and gas under controlled process flow conditions. The SwRI Multiphase Flow Facility performed this testing.
    - Neftemer Ltd. markets a through-pipe multiphase flow meter based on gamma-ray density measurements and high speed signal processing calculations. Neftemer technology was selected as the basis for demonstrating feasibility for a ROV-deployed through-pipe measurement. Neftemer supplied meter detector and surface communications interface hardware components. Neftemer also supplied expertise to assist in the design and marinization of the subsea meter.
    - Tracerco had the responsibility to design the shielding and source deployment mechanism for the source holder/source housing. Tracerco also supplied the sources and source handling field personnel.

3. Details of Task Plan

The goals for this project were set under the leadership of the JIP. In the broadest terms, the project goals were:

- Deliver multiphase flow measurements to the subsea at any time using an ROV/AUV for conveyance
- In this first attempt, use only non-intrusive (clamp-on) meters via ROV to simplify operation and maximize flexibility.
- Focus on development of the technique and the creation of interface standards, not the selection of a particular technology.

3.1 Prototype Concept

The concept has been defined by the need described above, which is to convey by ROV a clamp-on meter to the sea floor and take measurements that indicate flow rate. The drawing of Figure 1 serves to illustrate how this might be done. In general, it is anticipated that the ROV will pick up a metering package, either from the topside platform or from a subsea basket delivery, and clamp it in position on a Landing Zone in the flow line coming from a well, and near the metering equipment that might be in place, as shown.

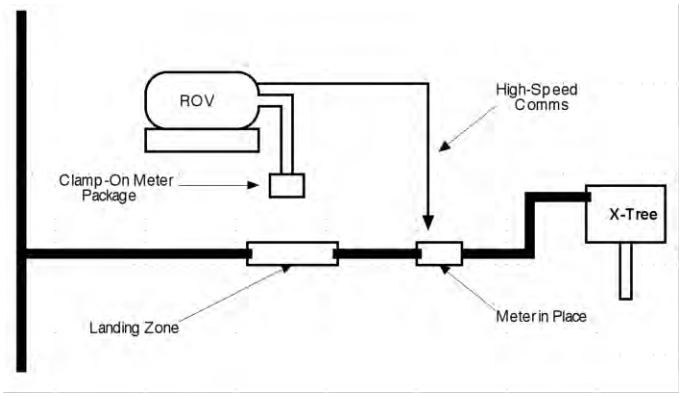

Figure 1. Drawing to illustrate a concept for ROV-Assisted Subsea Measurement.

In conceiving possible solutions for ROV-conveyed multiphase measurement, we understood that there may be a trade-off between simplicity of design and the ability to

meet all of the requirements. Specifically, we believed there would be some simple and inexpensive solutions that could be adapted easily to shallow water or low pressure environments – essentially thin pipe wall applications – but would not work in the deep water. As we conceived solutions for deeper water and higher pressures, thicker pipe walls, we would necessarily be faced with more complex solutions and more costly development. We felt it was important to map this out on a grid to visualize where any potential solution might be plotted on a water depth vs. solution complexity space.

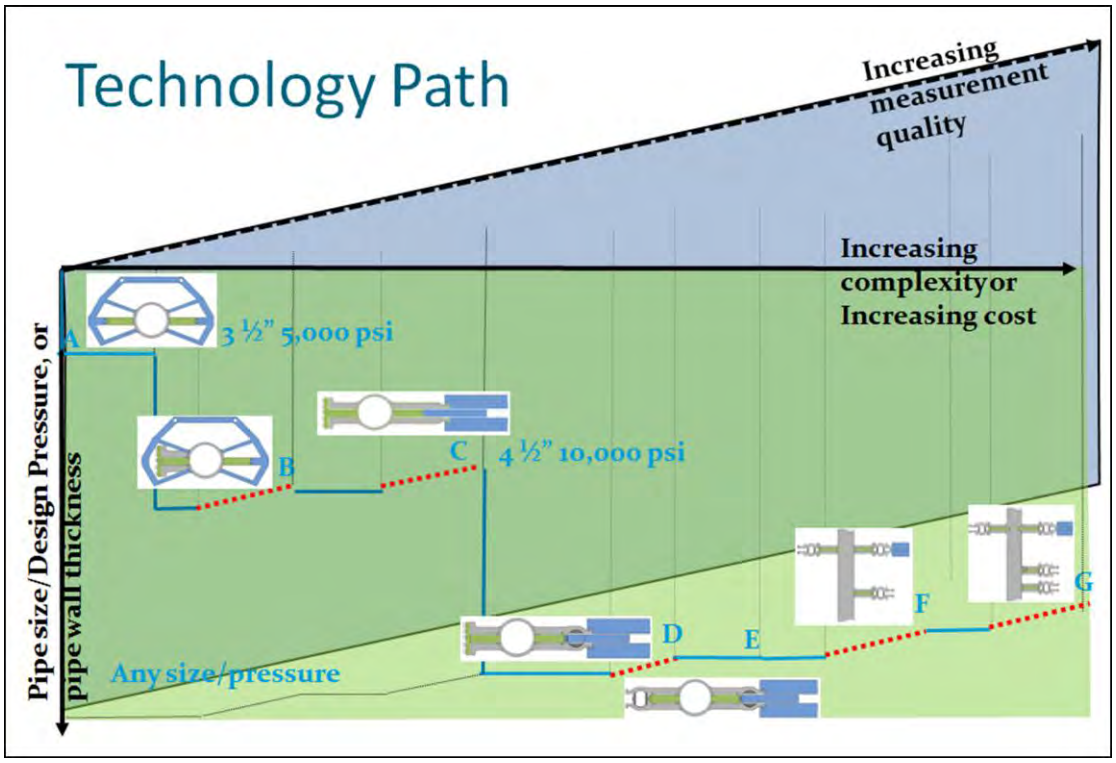

Figure 2. A Technology path for the development of ROV-conveyed multiphase measurement

Subsequently, recognizing that complexity and cost were not our aim, but rather measurement quality was, we realized the direction we wanted to go was toward deeper water and better measurement, while minimizing the complexity and cost. We visualized this as a three-dimensional solution space (Fig. 2.) delineated by the environmental challenge (such a water depth or design pressure), the complexity and cost of the solution, and the quality of the measurement solution. Within this space we began to plot potential solutions, and connected them to create paths to consider for the development of

technology. We returned repeatedly to this three dimensional plot in our discussions of which technology level we would target to build the first prototype of an ROV-conveyed multiphase meter. Most importantly, it helped us maintain perspective on how the present work moves us forward along the technology path we foresee, and what improvements and additional work we can begin to plan for the next step in the path.

Although there may be numerous opportunities in which technology such as this could be used, the primary application addressed by this task is that of verification of multiphase meter already in place in a subsea flow line.

No reasonable argument could be made currently that a clamp-on (or non-intrusive) meter can perform as well as the in-place meter with regard to accuracy in a head-to-head comparison. The non-intrusive device simply has too many disadvantages to overcome by placing its sensors on the outside of the pipe.

However, the clamp-on meter has certain distinct advantages when used in this application. For one, it should be "fresh", not altered by months or years of production and possibly recently calibrated. Secondly, it can be transported among several flow lines in a relatively short period to give a comparative flow response. Finally, although absolute verification is desirable, verification relative to other commingled wells may be sufficient in many instances.

To evaluate various measurements as a candidate for a clamp-on sensor package for subsea measurement requires an understanding of three main things:

- what we can expect from available sensor systems
- the constraints and future operability capabilities for ROV operations
- the landing zones requirements for a clamp-on sensor system

Several technologies were considered for non-intrusive clamp-on sensors for the purpose of measuring flow. There are most likely additional technologies that may apply well, but the following were identified as candidates:

- single gamma densitometer

- pulsed sonar array
- ultrasonic “pitch and catch”
- tracer detection
- signature recognition approaches

The challenges for these technologies include the ability to measure mass flow rate in multiphase, liquid-dominant flow in addition to the marinization of topside instrumentation. The key criteria we set out on which to judge candidate technologies include the:

- Sensor’s suitability for the harsh subsea environment
- Sensor’s size/suitability of ROV manipulation
- Measurement accuracy and repeatability
- Sensor Technology Readiness Level (topsides and subsea)
- Instrumentation operability
- Landing zone flexibility (the less stringent requirements the better)
- Ease of clamp-on deployment
- Measurement application history
- Usefulness of measurement to determine mass flow rates
- Communication bandwidth and power requirements
- Ability to provide measurement in near-real time

Given the limited technologies available and the many challenges present, we expanded our consideration to more intrusive approaches to measurement that offer a “clamp-on” type of deployment.

Figure 3 shows the meter in a frame approaching the landing zone. (The ROV is eliminated from the diagram for simplicity). Figure 4 shows the meter frame in position in the landing zone, with the frame secured and source and detector deployed next to the pipe.

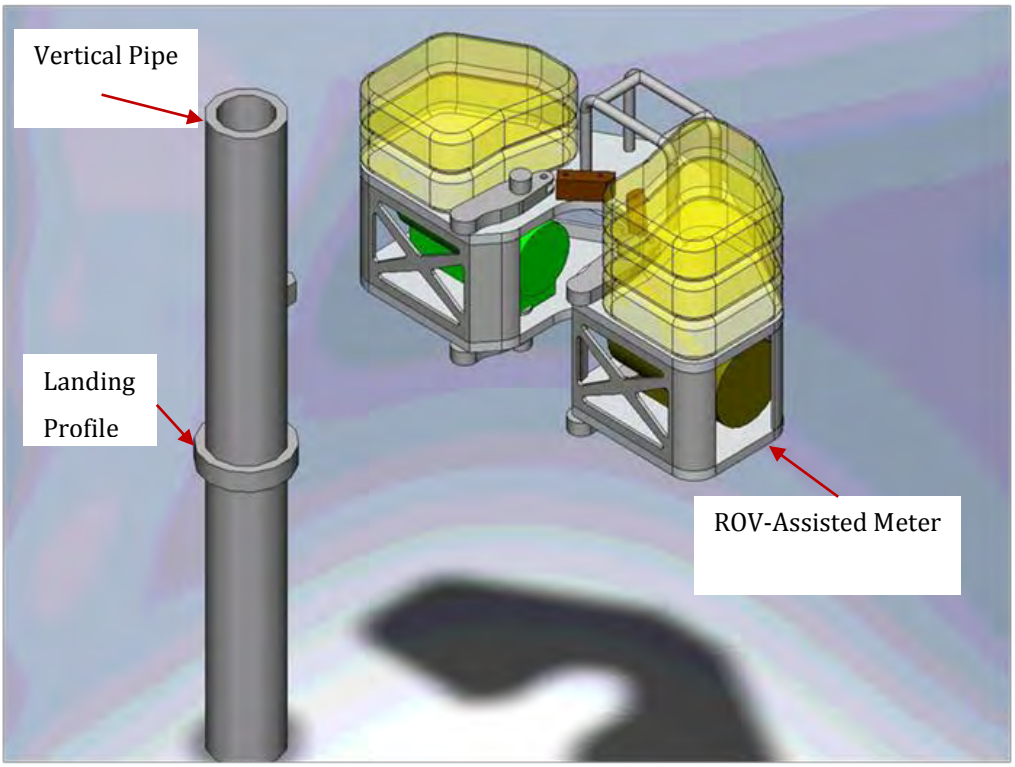

Figure 3. ROV-Assisted Meter Approaching Landing Zone

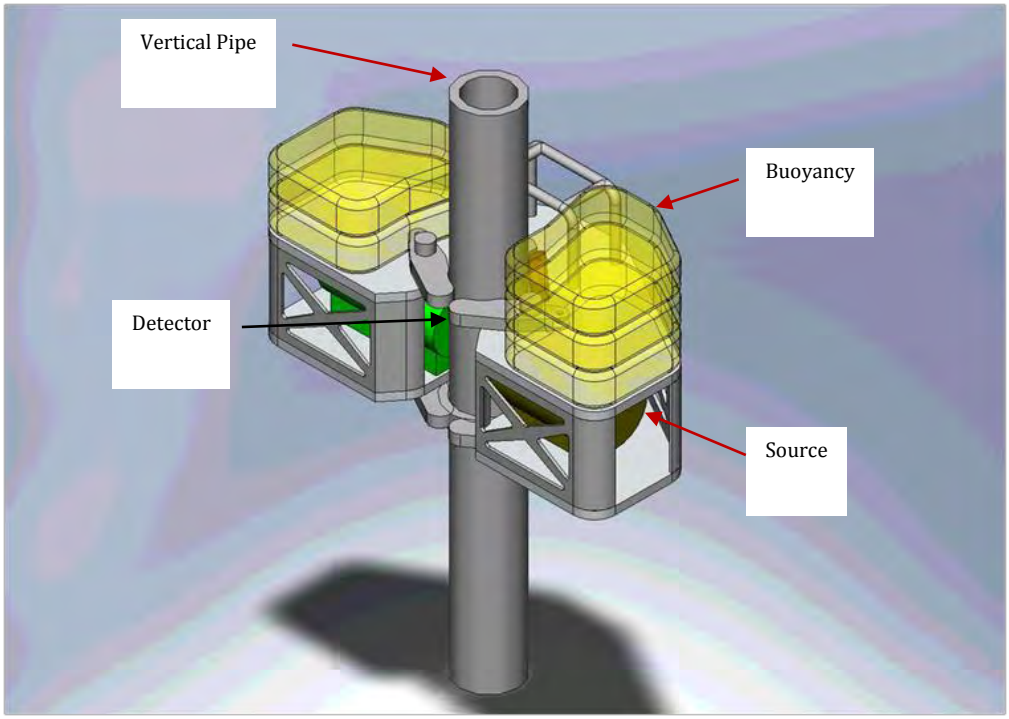

Figure 4. ROV-Assisted Meter after Landing, with Meter Secured

3.2 Detailed Requirements

After establishing broad goals, a more detailed set of requirements were established. To define the requirements for the design and fabrication of an ROV assisted subsea flow meter, we established a framework within which we defined core objectives. Detailed discussion of these framework requirements is made in a previous paper.[4] The core objectives of the ROV assisted metering solution are summarized below.

Table 1. ROV-Conveyed Multiphase Meter Requirements

	Objective
Power & Communications	- From surface via umbilical and ROV
Intrusiveness	- Clamp-on measurement system; may have permanently installed intrusive sensor
Field Maturity	- Green fields only; brownfield specific objectives not in scope
Measurement Independence	- Purpose is to verify existing meter; not a requirement that this measurement a stand-alone accurate measurement
Gas-Liquid and Water-Liquid Fractions	- Liquid-dominant flows - 10%<GVF<70% - 10%<WLR<50%
Water Depth	- At least 5,000 ft. water depth
Pressure/Temperature	- Under 10,000 psi, 300 deg F
Flow Line	- Single well flowline 3” to 6” diameter
Landing zone	- Bare pipe (may be prepared, have special weldments, etc.) - Under 3 ft (1m) long - Horizontal or vertical - - clean pipe interior not required

ROV operation	- Temporary, portable, to limit qualification requirements - Fly to place from surface or subsea - Meets API-17H (ROV)
Design life	- Landing zone: 20 yrs - Meter & clamp-on tool: 4 weeks continuous use
Measurement	- Total mass flow rate at good accuracy - Oil flow rate at reduced accuracy - Auxiliary measurement (e.g., P and T) not in meter design; assumed to be available from existing instrumentation
Calibration	- Calibration with well fluids is acceptable
Other	- Use only existing, proven technologies, even if no subsea experience - Access to full data set from permanent MPFM is allowable - Measurement performance may be less than existing meter

4. Execution of Plan

The expertise of several technical experts from the JIP member companies was a major benefit in weighing the options that the technology path offered. In view of schedule and budget and a common interest in the simplicity of a non-invasive, "read through the pipe" approach, it was decided to proceed with a clamp-on concept. Several multiphase flow measurement technologies were considered, but a gamma density measurement was eventually selected for its ability to ready through pipe, its track record in the field, and its ability to provide fluid mixture density in addition to flow rate.

Neftemer Ltd. was selected to supply the key meter components of the Neftemer meter, which would be used in the construction of the subsea prototype. The Neftemer meter has been used extensively for over a decade in Russia and other countries for multiphase flow rate determination. The methodology of the Neftemer meter has been presented previously,[5] but, in brief, it uses a single gamma source and detector positioned opposite each other, centered and external to a vertical pipe, and makes a time derivative measurement of the bubble fraction to determine gas and liquid velocities and flow rates. Its track record is primarily with smaller producing wells and heavier oil, where other multiphase flow measurement approaches struggle to perform well.

A gamma source was supplied by a local supplier, Tracerco, a company with expertise in source shielding design as well as field operations. The repackaging of the source and detector, the design of all other meter components for subsea deployment, and the marinization of the meter was performed by Oceaneering, a company with experience in deep water ROV operations and ROV tool interface design and fabrication.

Although the Neftemer meter was selected for use in the project to develop a prototype ROV-assisted subsea meter, the objective of the project was not to marinize a Neftemer meter. Rather, the Neftemer meter was used to demonstrate the concept of ROV-assisted measurement. The objective of the project was to build a prototype meter that could be applied not only to gamma density measurements but to a variety of other types of

measurements. In particular, any other measurements utilizing a signal source and receiver positioned opposite each other could be used in a similar manner.

4.1 Landing Zone Design

Early on, it was envisioned that developing a clamp-on technique that could be applied to any bare subsea pipe might be a difficult requirement to meet on a first attempt at building a prototype ROV-assisted meter. For that reason, the requirements allowed for weldments or attachments that might prove useful in the positioning of the meter onto the pipe. "Through-pipe" measurements have the disadvantage that the pipe itself may interfere with the fluid measurement. Though the pipe effect can be removed by making empty pipe reference measurements, the gamma density measurement remains quite sensitive to the source-pipe-detector geometry.

Initial work on the concept focused on the requirements for the repeatability of the position of the source and detector on the pipe in order to be able to compare measurements over time from different installations. It was determined that a precise positioning of the source and detector in both the vertical dimension as well as the azimuthal direction was a chief requirement.

The design calls for a two-piece bolted-together conical shaped seat which clamps onto the vertical pipe, and a matching inverted cone profile collar which is integral to the meter frame. Figure 5 shows the seat shaded, and the collar stripe shaded. The collar sets down on the seat. The seat has an exterior vertical slot and the collar inside profile has a short protruding round pin, which is guided through a tapered entry into the slot. The slot can be seen in Figure 6. When the meter frame, which hangs off the collar, is properly landed, the conical seat provides position control in the vertical direction, while the pin-in-slot provides position control in the azimuthal direction. The weight of the meter frame is used to keep the meter frame landed. The design calls for buoyancy sufficient to maintain a weight in water of approximately 200 lbs., or 100 kg.

To position the frame on the pipe, the meter frame has a cut-out with a tapered entry on one side of the frame. This is shown by the plan view in Figure 6. The procedure for landing the meter frame is discussed in a subsequent section of this paper.

The landing zone collar, as shown, is a bolt-on design. This design serves the purpose for position control of the meter frame. It is fairly easy to imagine, however, how this design could be adapted to utilize an ROV operated coupling for ROV placement of the landing zone collar on the pipe, as could be used in a brownfield installation.

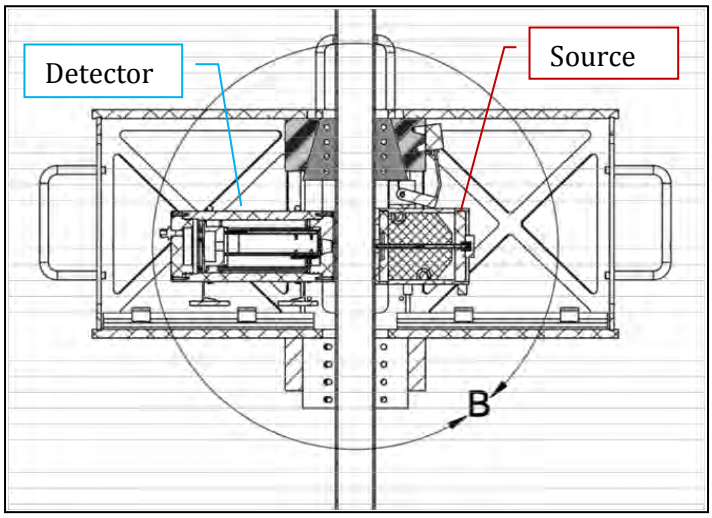

Figure 5 Cross-section of meter frame landed on vertical pipe, showing landing collar (striped) and clamp-on landing zone seat (shaded)

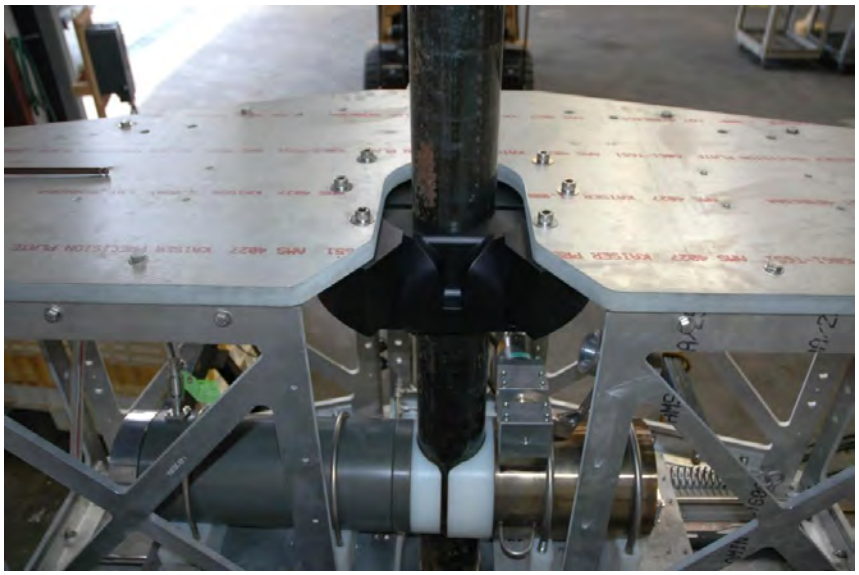

Figure 6. Photograph of meter frame landed on vertical pipe, showing landing collar and clamp-on landing zone seat (both black), and frame cutout

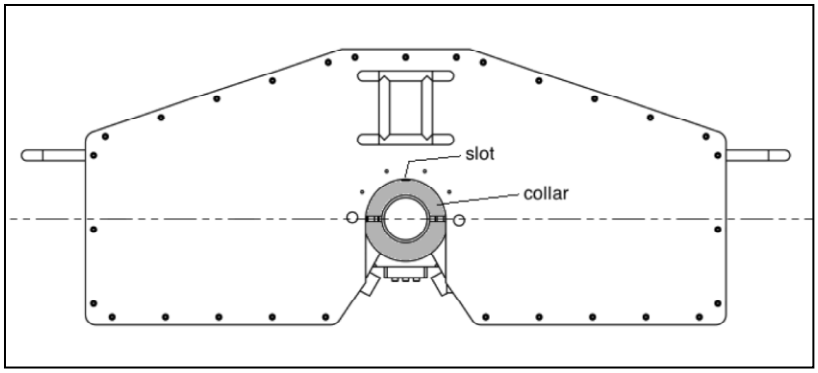

Figure 7. Plan view of meter frame landed on vertical pipe, showing clamp-on landing zone seat (shaded) with slot for the collar pin.

The characteristics of the pipe on which the ROV-assisted meter is installed were dealt with at length over the course of this prototype design. For the purposes of this project, it was decided to maintain the characteristics of the current Neftemer topside meter as much as possible, so as not to introduce too many new developments into the prototype and risk an unsuccessful test. To that end, it was decided to use the detector assembly unmodified and the source strength as installed in topside Neftemer meters. The current topside Neftemer meter uses a 150 mCi Cs-137 source, which provides a total pipe attenuation budget of 18 mm of carbon steel.

In contrast to the topside Neftemer meter, the ROV-assisted meter would have two additional housing walls to penetrate: the source housing and the detector housing. This reduced the allowable budget for pipe wall thickness for the flowing pipe. The final solution resulted in a source housing and detector housing wall thickness of approximately 3 mm each. This left 6mm for wall thickness of the pipe. Although this is not typical of subsea pipe wall thickness, it was ultimately determined that once the concept is demonstrated with this prototype meter, the source strength could be increased to apply the measurement to thicker walled pipe. The landing zone used for the prototype meter was 4 in. Schedule 40 carbon steel pipe.

4.2 Meter Arrangement

The key requirement in designing the arrangement of the meter components was the need for repeatability of the measurement, or repeatability of the position of the meter

components for metering. While the positioning of the meter frame on the pipe landing zone was addressed by the landing zone and seat and collar design, the positioning of the source and detector relative to the pipe was to be addressed by the arrangement of the meter components within the meter frame.

It was determined that an advantage could be had in maintaining the alignment of the source beam and the detector crystal if the two were mounted on the same platform. Like a serving tray with the source and detector fixed in place and in alignment, as long as the serving tray was positioned correctly relative to the pipe, then the source and detector would be correctly positioned.

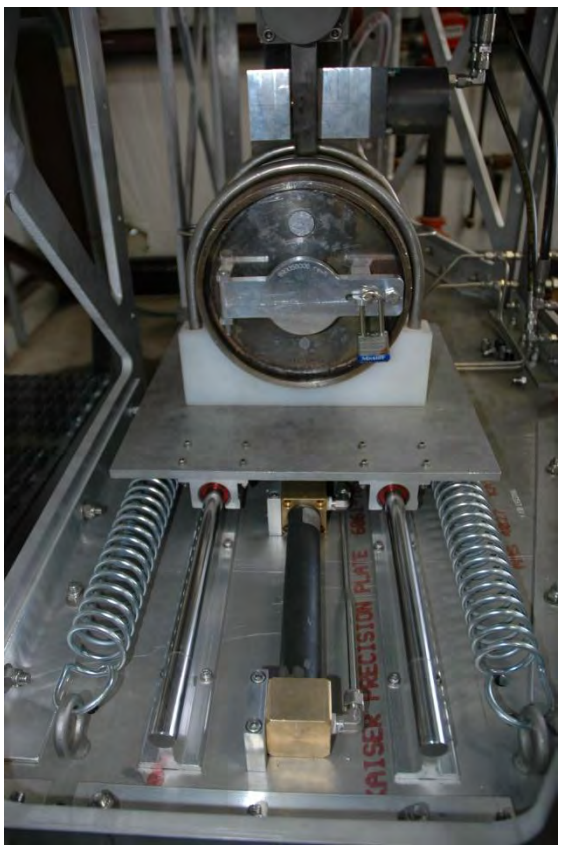

Figure 8. Source housing on rails with hydraulic piston, spring return.

Given that the meter frame is slotted so that it can be installed on the vertical pipe from a side approach, it was necessary that the source and detector be positioned back away from the pipe during the landing of the meter frame. Although the land installations of the Neftemer meter permit the positioning of the source and detector some distance of an inch or more (a few centimeters) away from the pipe during measurement, subsea this could not be tolerated because it would allow seawater to be in the measurement beam path, which would adversely affect the measurement.

Because the measurement position of the source and detector was required to be snug against the pipe, and the landing position required them to be backed away from the pipe, the source and detector were installed on rails. As shown in Figure 9, this was achieved with hydraulic cylinders to push the devices toward the pipe, with spring return when hydraulic pressure was released. The spring

return also served to provide a fail-safe “open” position so the frame could be removed from the pipe in case of loss of hydraulic power. The rails were positioned on the base plate of the meter frame to ensure proper alignment of the source beam and the detector crystal in both the vertical plane as well as the horizontal plane.

To keep the entire meter frame upright and balanced, and to reduce the weight in water that the ROV must bear, the design calls for buoyancy foam blocks to be mounted above the meter frame. In the construction of the prototype, these buoyancy blocks were not constructed in an effort to keep the cost down, because they are fairly expensive and yet also fairly routine to fabricate.

4.3 Deployment Method

The requirements of the prototype meter, summarized in Table 1, did not specifically address the location of the landing zone or meter deployment location. However, it was envisioned that since the objective is to verify an existing meter, that the ROV-assisted meter would be positioned somewhere very close to an existing meter. In deep water, there are two commonly selected locations for the position of a permanent subsea multiphase flow meter. These are on the Christmas tree, and on the jumper close to the Christmas tree. A likely location for the ROV-assisted meter might be a short vertical length of the jumper, close to the multiphase flow meter.

The ROV can easily approach the jumper from the side, avoiding any need to fly under the jumper. In a Greenfield development, the landing zone could be planned and positioned anywhere close to the installation site of the multiphase flow meter or other desirable metering location.

To position the frame on the pipe, the meter frame is presented to the vertical pipe with the tapered entry cut out facing the pipe. This is shown in Figures 6 and 9. Approaching the pipe from the side, above the clamp-on landing zone seat, and in approximate alignment with the seat slot, the ROV guides the meter frame until the vertical pipe is fully inserted into the meter frame cut out. The ROV then guides the meter frame down until the collar pin engages into the seat slot, and the collar lands on the seat. The ROV uses an underwater

camera to confirm proper landing.

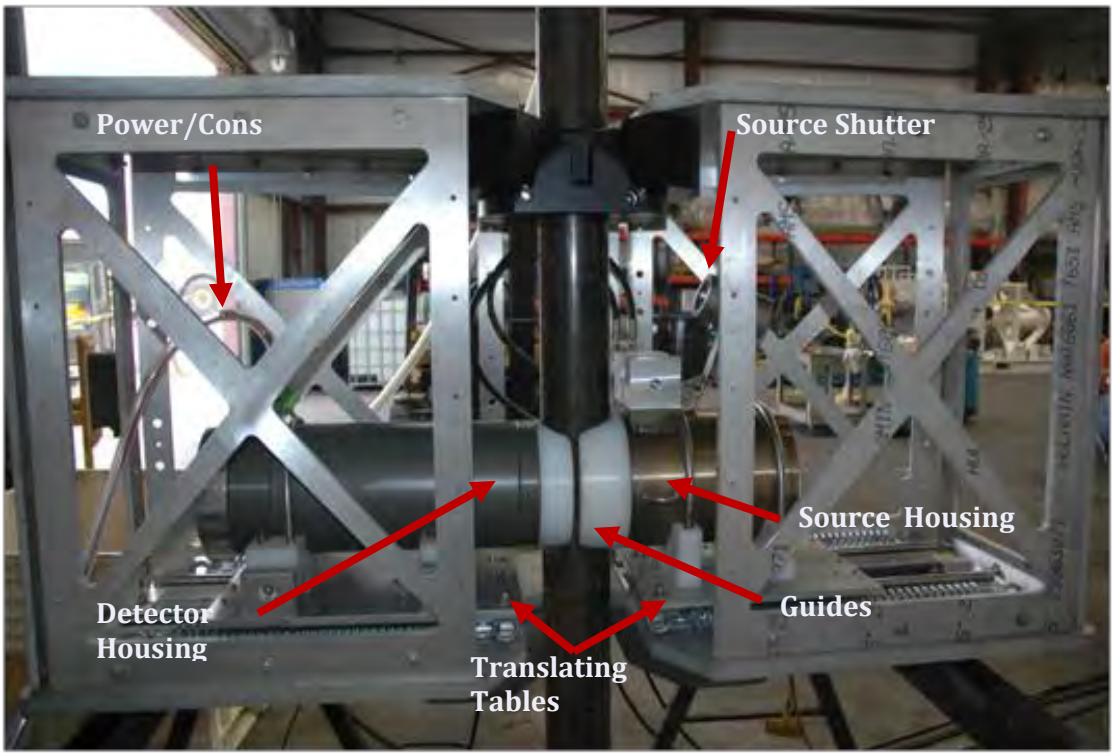

Figure 9. Source housing on rails with hydraulic piston, spring return.

It is anticipated that the meter would be lowered to the seabed on a skid, with the meter seated onto a dummy pipe for transport. Once the meter is located near to the installation site, the ROV would pick up the meter frame and fly it to the landing zone and land it on the meter. The ROV can then make up the power and communication connections required for meter operation.

4.4 Gamma Source Operational Safety Considerations

When the meter is deployed subsea, surrounded by sea water, there is no real concern for radiation exposure around the source and behind the detector. This is not the case, however, when the meter is on the deck of a service vessel, or in the shop for maintenance and operational checks. For that reason the radiation exposure risk was treated the same for the subsea meter as for any topside meter.

The current Neftemer meter source holder design was used as a basis for the design of the subsea source holder. Essentially, the source was encased in a thick shield of lead on all sides except for the collimator, which directs the gamma beam at the detector. Lead shielding was also used on the back side (the beam exit) of the detector. When the source and detector are positioned for measurement, the radiation levels at all points on the surface of the meter components are below allowable radiation exposure limits.

When the source and detector were pulled back on their rails away from the pipe, a shutter was added to the source housing in order to eliminate further risk of anyone exposing their hand to the gamma beam. As shown in Figure 10, the shutter resembles a large hammer head on a bent handle. Mounted on top of the source housing, hydraulic power was used to move the shutter down and directly in front of the beam exit from the source housing. The design called for spring driven closure of the shutter so that the shutter is fail-safe closed. On the prototype the spring closure encountered some difficulties, so hydraulic power was used. Hydraulic power was used to open the shutter, or lift the shutter away from the beam. The shutter is opened before the detector and source are moved on their rails up against the pipe.

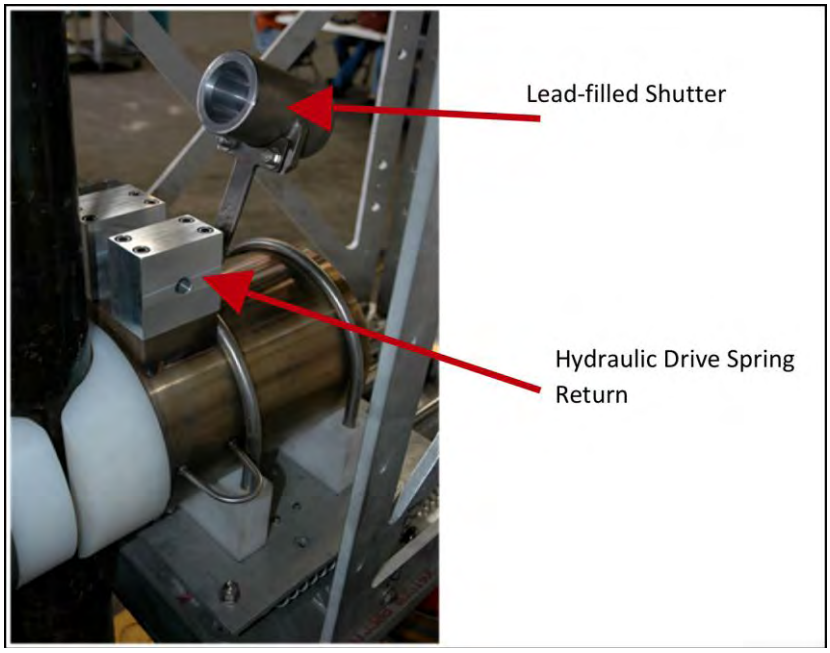

Figure 10. Source Shutter Mechanism, shown in the Open Position

4.5 Electrical and Hydraulic Power Supply and Communications

Because the metering operation is considered to be a temporary operation, and to simplify the meter design, it was determined that the electrical and hydraulic power and the communication link would be supplied to the meter via the ROV. As explained above, hydraulic power is used to move the shutter away from the gamma beam, and to push the detector and source housing into the measurement position against the pipe. This requires the ROV to remain on location throughout the metering operation. Hydraulic and electrical connections are made using standard subsea interface components. The ROV uses its robotic arm to grasp the connector coming from the ROV and insert it into its mate on the meter frame. The electrical power and communication travel via the ROV umbilical back to surface, where it is interfaced to the Neftemer meter flow computer and service laptop.

4.6 ROV-Assisted Measurement Operation

The classic scenario in which the ROV-assisted meter might be used is in a field where several subsea multiphase flow meters are installed, and the allocation imbalance indicates measurement discrepancy between the total volume measured reliably at surface and the sum of the well stream measurements made individually with subsea multiphase flow meters. To find the source of measurement error, an additional measurement device may be used as a check against the subsea meters.

However, a clamp-on measurement made externally to the pipe is unlikely to be more accurate than the installed subsea meter which is the object of the verification. A methodology that would apply to make such a verification is to use the ROV-assisted meter to establish a track record of repeatable comparisons against the installed multiphase flow meter. In this manner, the ROV-assisted meter would be deployed on a regular basis to establish a historical record of measurements. The deployment period might be annually or biannually after an initial phase. In doing so, the confidence in the ROV-assisted measurement is enhanced by establishing a trend of measurement comparisons.

For the gamma density measurement, as well as many other possible measurement technologies, it is necessary to have an empty pipe reference measurement as a base reference in order to evaluate the measurements made on the same pipe containing flowing

fluids. This reference measurement needs to be made on the landing zone prior to its installation subsea. As an alternative, or to augment this, a second, identical piece of pipe can be used for establishing a history record of empty pipe reference measurements. This identical empty pipe, or dummy pipe, can be transported to the seabed with the meter in order to make the empty pipe measurement in conditions as close as possible to the line measurement.

In addition to the empty pipe reference, the gamma density measurement also requires attenuation reference measurements made on the liquid phases, oil and water. As in any multiphase flow meter installation, getting reliable, representative fluid properties is best achieved by analyzing fluid samples extracted from the subsea metering location. A methodology and a description of such a sampling device has been developed and tested.[6] The development of this prototype ROV-assisted meter included the conceptual design of liquid reference measurements made using dummy pipe as in the empty pipe reference measurement. In this case, the dummy pipe is filled with liquid sample, either oil or water. The liquid reference measurement can be made at the seabed after the empty pipe measurement and just prior to making the measurements on the flowing pipe. The empty pipe, oil-filled pipe and water-filled pipe are mounted on the same skid and lowered to the seabed with the meter frame.

The actual testing of the flowing well with the ROV-assisted meter should not be any more time consuming that a normal well test. The test duration may be a few hours or as short as a half-hour. This depends somewhat on the flowing characteristics of the well. Well tests of 12 or 24 hours, or even several days are achievable. Such longer tests are more likely to be limited by logistics of the ROV or operational cost. It is advisable to conduct not just a single rate well test, but to vary the rate in steps so as to establish a dynamic performance characterization of the well. This not only enhances the well evaluation but improves the comparison record.

4.7 Prototype Flow Loop and ROV Tank Testing

An important part of the development project was the testing of the prototype meter to demonstrate its ability to function as designed. There were three aspects of testing undertaken to achieve this: static testing, flow testing and ROV-tank testing.

The static testing consisted of making a series of measurements on a non-flowing pipe to test the repeatability of the positioning of the source and detector. Here, the prototype was tested using the collar/seat arrangement to locate the meter frame on the pipe, and the rails on the meter frame to position the source and detector against the pipe. These tests confirmed the collar/seat arrangement provided a very repeatable measurement.

Additional static measurements were made to evaluate the tolerance for side-to-side misalignment of the detector with the source beam. These tests were done to help in determining the tolerances that could be defined for the alignment of the source and detector rails on the meter frame, and the requirements for frame rigidity to prevent flexing which might cause misalignment. These tests confirmed calculations that more than approximately ¼ inch of play in the alignment was detrimental to the measurement repeatability.

One additional static test was performed to confirm the viability of using a stronger source to measure thicker pipe wall. To perform this test, two half shells of 9 mm wall thickness pipe were attached to the outside of the pipe to double the total steel thickness from 18 mm to 36 mm. A source of approximately double strength was used in this test. The standard source used in the testing was 161 mCi. For the double wall testing, a source of 289 mCi was used and the test results were positive.

Figure 11. Landing zone pipe being lowered into 6 ft deep tank. The conical seat to land the meter can be seen.

Flow loop testing was conducted at Southwest Research Institute. The purpose of the testing was to demonstrate that total mass flow rate could be determined with good accuracy. The first step of the test was to make a comparison of measurements in air and submerged under water. The lack of discernible difference between the sets of measurements confirmed the flow testing could be conducted with the meter submerged. To conduct these tests, a water tank was constructed such that the landing zone section of pipe was in the tank, and the landed meter was sufficiently submerged. This is shown in Figure 12. The

objective of verifying that total mass flow rate could be determined with the prototype meter was achieved.

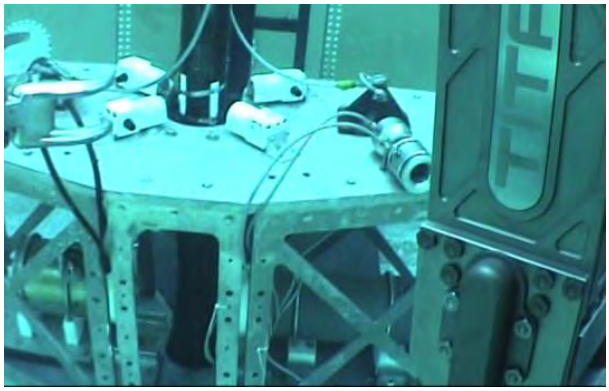

Figure 12. Using an ROV to land the meter frame onto the pipe.

The final, and most significant test performed was the actual manipulation of the prototype meter in a test tank with an ROV. To conduct this test, the meter was lowered into the tank mounted on a skid. The ROV was then lowered into the tank and flown to the meter. The ROV then lifted the meter and moved it into position on the test landing zone section of pipe. This test was repeated three times. Lasers, shown in Figure 10, were used to track repeatability of the measurement position to confirm the feasibility of the operation. The testing was captured on video, which provides the best record of the success of this test.

5. Results and Deliverables

This project has achieved a major milestone in fabricating and testing the world's first deep water subsea ROV-assisted clamp-on multiphase flow meter. The original scope of work for this project were:

- Publish Draft standards for customizing clamp-on sensor packages, "landing zones" and relevant interfaces.
- Surface test prototype clamp-on metering system with ROV mechanism, including test for handling and installation capabilities.
- The validation meter will be qualified through testing in surface multiphase reference flow facilities, all functions will be verified.
- The complete ROV-assisted clamp-on metering system will be tested in an underwater (tank) facility.
- Methodologies and algorithms will be created to use clamp-on measurements like these to reduce the uncertainty in allocation among wells. Document the most promising of such methods, and test them with numerical simulations.
- Final Report and presentation with recommendations for future activity.

6. Conclusions and areas for continued R&D investigation

Not an insignificant part of this achievement was the ability to gather the expertise from seven major deep water operating companies to contribute a wide range of expertise into the design process. The collaborative approach has permitted the capturing of the core requirements of what functionality a ROV-assisted meter needs to have, what type of measurements are most useful, what is expected of the performance of the meter and how the meter should operate in the deep water environment.

The project demonstrated the viability of the approach to construct a meter frame which contains a signal source component and a receiver component, and place the meter frame onto a vertical pipe in a repeatable and reliable manner such that the signal source and receiver components can make a mass flow measurement on the fluid flowing in the pipe.

The prototype meter was built with the purpose in mind that the upstream industry might use the results of this project as guidance in designing and building commercial products which are capable of delivering a verification measurement at the location of deep water infrastructure.

It has been recommended by the JIP steering committee that the development of subsea ROV-assisted metering be further investigated to advance the capabilities of measurement, to test different measurement technologies and landing configurations, such as are indicated in figure 2 and the referenced paper, Remacle, et al. [4]. It is also the wishes of the committee that this prototype, or similar, be deployed in the subsea marine environment for real field verification of what was demonstrated in this project in more controlled and benign conditions. It is hoped that in the near future the industry will be able to provide ROV-assisted measurement for deep water installations as described in this project.

Acknowledgements

The author would like to acknowledge the support provided by the US Department of Energy for the RPSEA Initiative, which has provided the impetus and funding for the work presented here. We acknowledge the RPSEA organization for their work in coordinating the DW1301 project, and their continued support of research in the area of deep water flow measurement technology gaps.

We also highlight and thank the members of the DW1301 Joint Industry Project who provided not only financial support for the project, but who contributed the expertise of their brightest and best subsea and measurement engineers. These are: BP, BHP, Chevron, ConocoPhillips, Shell, Statoil, and Total. We express our gratitude to each of the individuals in the DW1301 Task 2 working group. We also extend a hearty thanks to the key contractors of the project: Oceaneering, particularly Rich McCoy, Matthew Bryant, Josh Turnbull, Dick Vuyk; Neftemer Ltd, particularly Dmitry Gazin, Ivan Endovitsky, David Whittingham, Andy Jamieson; Tracerco, particularly Lary Pate, and Southwest Research Institute, particularly Adam Ufford and Flavia Viana. These dedicated technical staff put valuable efforts into this task to achieve a very meaningful step forward for safe and effective deep water oil and gas development.

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Appendices in this document are divided into two groups. Appendices A and B were developed with RPSEA funds and are open to the public. The other appendices contain information developed as part of the JIP with funding from the JIP. These appendices are available to JIP members on CMS (define).

Appendix A: Financials

Task 2 Activities	Actual Cost
Engineering, fabrication, testing:	$472,876
Radiation source design/supply:	$47,177
Meter Hardware and Technical Support:	$228,129
Flow Testing:	$23,566
Contractors, Miscellaneous:	$6,187
Direct Labor:	$311,937
Travel:	$19,812
Consultants:	$0
General & Administrative:	$82,285
Total Amount Spent: (end Aug 2011)	$1,191,969
Total Budget	$1,205,360
Amount Under Budget:	$13,391

Appendix B: Engineering Drawings

The complete set of engineering drawings may be accessed at:

http://www.rpsea.letton-hall.com/tiki-list_file_gallery.php?galleryId=167

The set of engineering drawings for the landing zone are provided below.

Landing Zone Design

The landing zone design developed for the ROV-conveyed measurement is a mechanism for the external attachment or positioning of a meter on a vertical subsea pipe. The landing and positioning sequence consists of two steps: landing the meter frame onto the vertical pipe, and positioning the measurement devices against the pipe for measurement. Although initially envisioned and sometimes referred to as a "clamp-on" meter, the landing or positioning of the meter frame on the pipe does not involve clamping. The landing mechanism is gravity based, and uses a cone-shaped seat with a pin-and-slot arrangement for positioning. Once the meter frame is positioned on the vertical pipe, the measurement devices are pushed hydraulically against the pipe into a clamp-like measurement position. The removal procedure is exactly the reverse, wherein the measurement devices are pulled away from the pipe, and the metering frame is lifted by the ROV off of the seat and away from the pipe.

The landing zone design is a key deliverable of the project task. An important advantage of the design is that it may be utilized for a number of different measurement technologies. By establishing and sharing publicly the landing zone design, the design can be called upon as an industry standard reference. As a standard interface, a deep water operator may design the landing mechanism into a subsea infrastructure while maintaining flexibility in the types of measurements and the suppliers that could be employed for making the required measurements.

The landing zone was designed to provide optimum repeatability of the precise positions of the measurement devices in both the vertical dimension as well as the azimuthal direction.

The design calls for a two-piece bolted-together conical shaped seat which clamps onto the vertical pipe, and a matching inverted cone profile collar which is integral to the meter frame. Figure 1 shows the seat shaded, and the collar stripe shaded. The collar sets down on the seat. The seat has an exterior vertical slot and the collar inside profile has a short protruding round pin, which is guided through a tapered entry into the slot. The slot can be seen in Figure 2. When the meter frame, which hangs off the collar, is properly landed, the conical seat provides position control in the vertical direction, while the pin-in-slot provides position control in the azimuthal direction. The weight of the meter frame is used to keep the meter frame landed. The design calls for buoyancy sufficient to maintain a weight in water of approximately 200 lbs., or 100 kg.

To position the frame on the pipe, the meter frame has a cut-out with a tapered entry on one side of the frame. This is shown by the plan view in Figure 3. The procedure for landing the meter frame is discussed in a subsequent section of this paper.

The landing zone collar, as shown, is a bolt-on design. This design serves the purpose for position control of the meter frame. It is fairly easy to imagine, however, how this design could be adapted to utilize an ROV operated coupling for ROV placement of the landing zone collar on the pipe, as could be used in a brownfield installation.

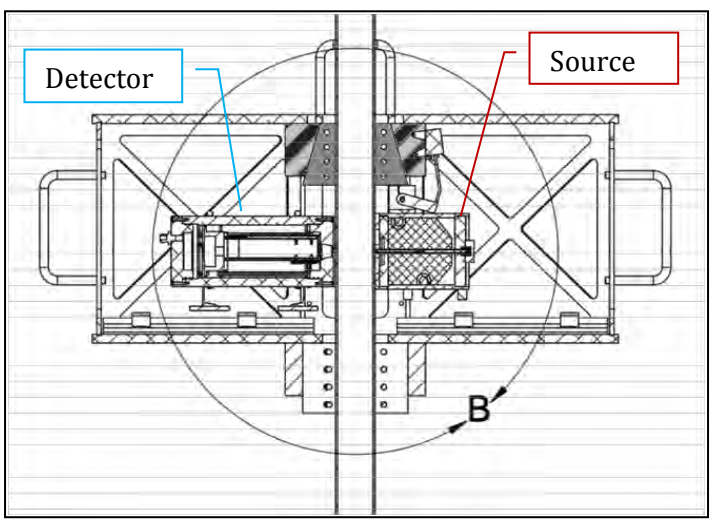

Figure 1 Cross-section of meter frame landed on vertical pipe, showing landing collar (striped) and clamp-on landing zone seat (shaded)

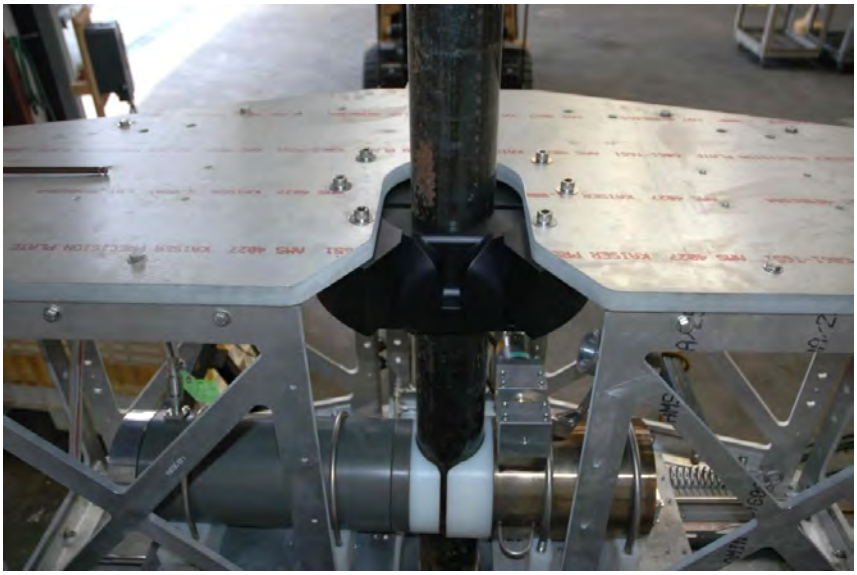

Figure 2. Photograph of meter frame landed on vertical pipe, showing landing collar and clamp-on landing zone seat (both black), and frame cutout

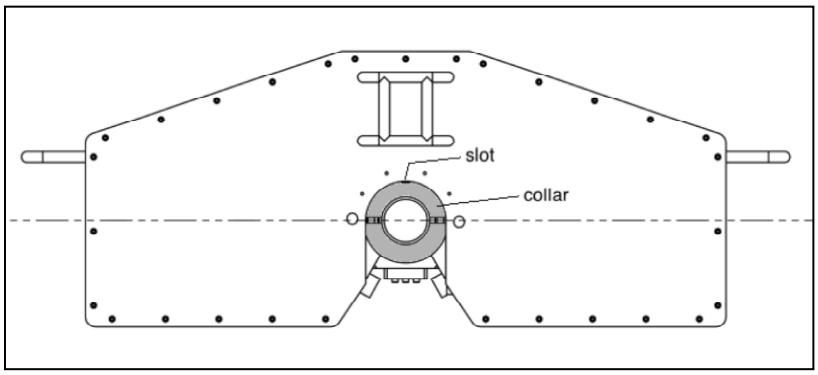

Figure 3. Plan view of meter frame landed on vertical pipe, showing clamp-on landing zone seat (shaded) with slot for the collar pin.

The prototype meter tested in the project task imposed some limitations on the pipe wall thickness, and hence the pipe used was 4 inch Schedule 40 carbon steel pipe, with 6mm wall thickness. Although this is not typical of subsea pipe wall thickness, the arrangement was sufficient to demonstrate the concept. Depending on the limitations of the measurement technology, thicker walled pipe may be used, and the subsequent dimensions of all corresponding pieces would need to be scaled up.

The drawings for the landing zone seat and the landing collar are provided below.

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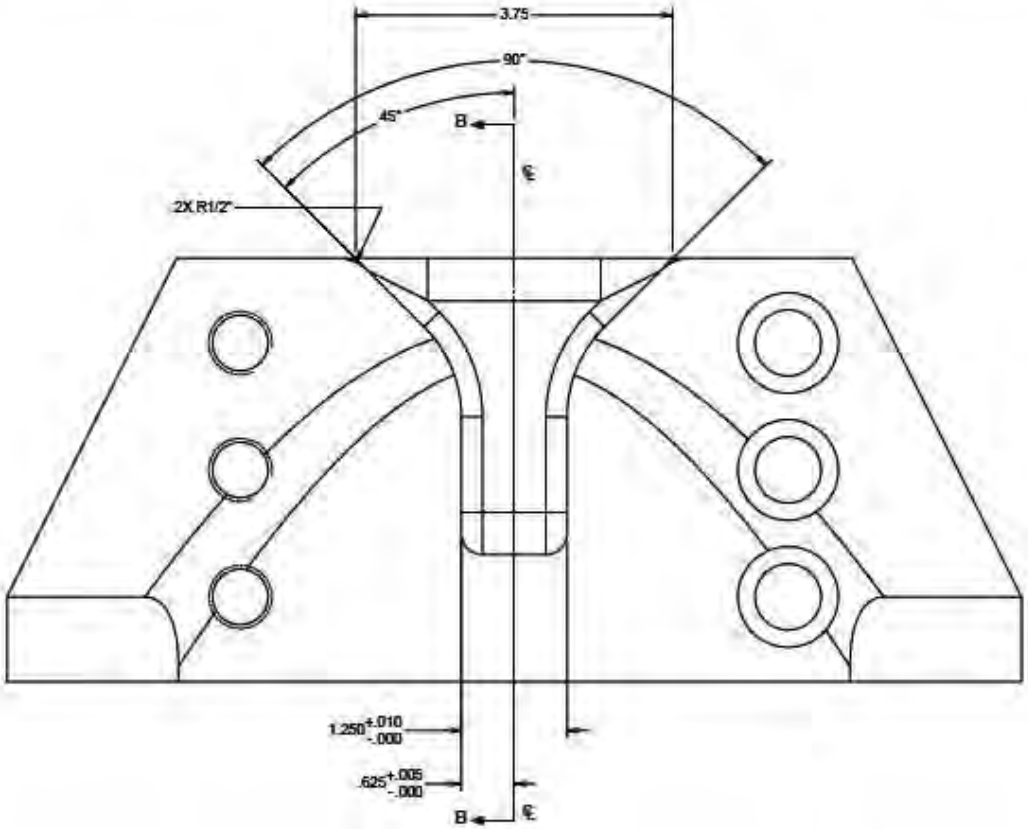

SECTION A-A
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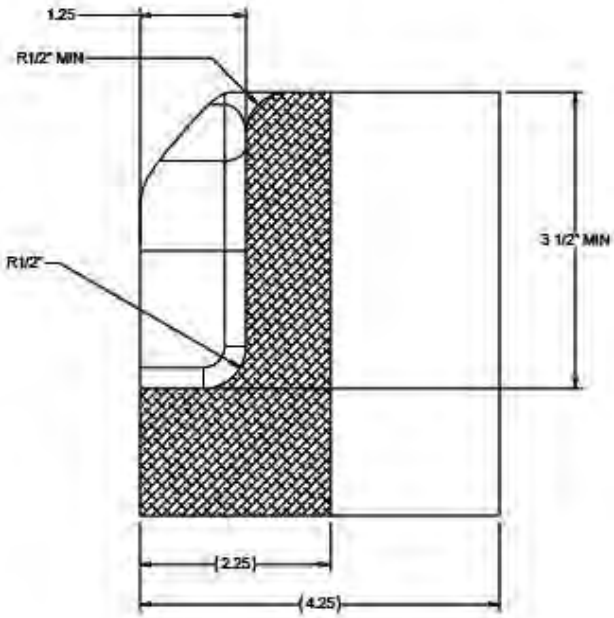

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3RD ANGLE PROJECTION

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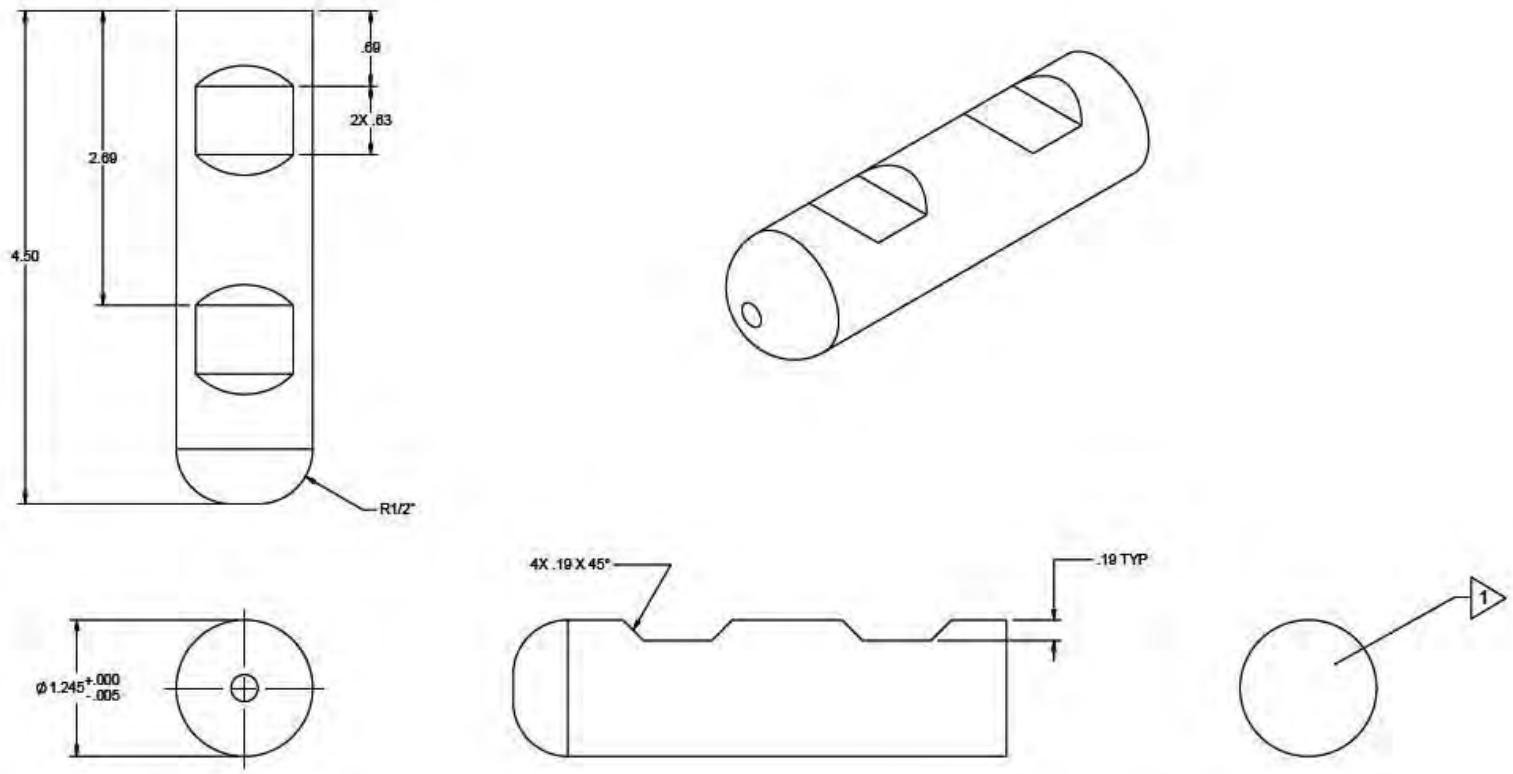

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NOTES:

MATERIAL: 316 SS	UNLESS OTHERWISE SPECIFIED: ALL DIMENSIONS ARE IN INCHES. DIMENSIONS IN [ ] ARE IN MM. FRACTIONS: ±1/64 DECIMALS: .X ±.1 .XX ±.03 .XXX ±.005 ANGLES: MACHINED ±0°30' OTHERS ±0° CONCENTRICITY: .003 BREAK CORNERS: .015 - .030 FILLET RADIUS: .030 - .050 SURFACE FINISH: 125 RMS	OCEANEERING Deepwater Technical Solutions — OCEANEERING INTERNATIONAL, INC. WWW.OCEANEERING.COM
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TITLE: MOUNTING CONE PIN
MOUNTING CONE
Component - Mechanical

DRAWN: MBRYANT	DATE: 28 Apr 10	3RD ANGLE PROJECTION	DO NOT SCALE
SUBM BY: MBryant	DATE: 03 May 10	SIZE: D	DWG. NO: 990052692	REV: A
APPVD BY: JTumbell	DATE: 03 May 10	SCALE: NTS	WEIGHT: 1.5 LBS	SHEET 1 OF 1

eSIGNATURES ON FILE

Appendix C: Static Testing

The static testing report may be found at:

http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=753

Appendix D: Flow Loop Testing

The flow loop testing report may be found at:

http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=773

Appendix E: Tank Testing

The tank testing report may be found at:

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Additional recommendations for improvement made following the tank testing may be found at:

http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=809

RPSEA

High Pressure-High Temperature Sensor Development - Final Report

07121-1301-Task3.FINAL

Improvements to Deepwater Subsea Measurement

07121-1301

December 29, 2011

James E. Hall, Ph.D.
The Letton-Hall Group
Houston, Texas

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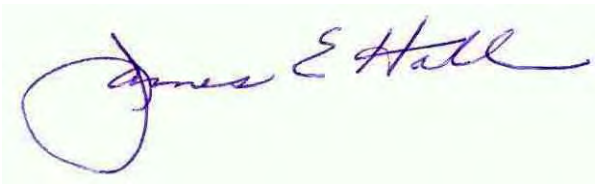
Abstract

The goal of this task was to make sensors for accurate flow measurement available for extreme (high-pressure, high temperature) subsea production environments. However, due to the small numbers required, the needed technology might not be developed through commercial-only forces. The key required element is a combination pressure-differential pressure (P-DP) sensor that can be used at pressures and temperatures that are far higher than current standard conditions. The benefit from this work is the ability to measure flow in these hugely important HPHT fields, thus permitting accurate revenue/royalty allocation and improved recovery. Since a HPHT DP subsea sensor is not currently available, the Letton-Hall Group LLC (LHG) and its subcontractor, *axept* LLC, concentrated on overcoming the numerous technical challenges required to develop this unique sensor. These new techniques are discussed in this report and the performance data for the resulting device is presented.

Prepared by:	Approved by:
James E. Hall, Ph.D. (LHG)	 Date: December 30, 2011

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1. Introduction

Subsea multiphase flowmeters are increasingly being used as production has increased in the Gulf of Mexico as well as other locations around the world. Most of the currently installed subsea multiphase and wet-gas flow meters are limited to measurement of production fluids at a maximum temperature of 125°C and operating pressures of 10,000 psig. Improvements are required in the design of the mechanical components of the meters to allow qualification for operational pressures up to 15,000 psig. For operation at that pressure, the flow meter must be tested at 22,500 psig. The temperature limitation is related to the sensors that measure the produced fluids.

Ultra deep and long tie-back systems may require subsea high pressure-high temperature (HPHT) multiphase metering system for well test and allocation measurement instead of using a test flow line. Three types of measurement are needed in this environment: temperature, pressure, and differential pressure. These HPHT sensors, along with accurate flow measurement, could provide the basis for accurate revenue and royal allocation, as well as improved reservoir management.

This project was launched as part of the RPSEA Project DW1301: Improvements to Deepwater Subsea Measurement with the realization that this sensor market is small and the needed HPHT sensors might not be developed through a commercial-only approach. Thus, this project focused on qualifying and/or developing sensors for the HPHT environment:

- Temperature (production fluids) ≥ 250°C
- Pressure (production fluids) > 15k psig
- Water depth >3000 meters (4.3k psig)

2. Organization

An important aspect of the execution of this task was to pull together a team to execute the plan. The team members were:

- Frank Ting (Chevron)-Task Champion. In this role, Dr. Ting served as the lead technical interface between the JIP members, task manager and subcontractors.
- Jim Hall, Ph.D. (LHG) - Task Manager. Dr. Hall was the overall manager of the effort.
- Task Working Group. JIP members who have special interest in the Task technology or application. : BHP Billiton, BP, ConocoPhillips, Chevron, Shell, Statoil and Total.
- Subcontractor - Because of their extensive experience in micromachined silicon design and fabrication, *axept* LLC was selected to design and fabricate the necessary HPHT DP sensor components. *Axept* is geographically located to take advantage of some unique capabilities that each of their locations has to offer. In Palo Alto, CA, members of the *axept* team focus on the design, packaging, and electronics. Fayetteville, AR is both the corporate headquarters for *axept* and the wafer fabrication center. Their Newport News, VA, facility primarily focuses on packaging, testing and application development
- Subsea flowmeter manufacturers: Solartron, Expro Matre, MPM, and Schlumberger-Framo expressed an interest in testing the resulting HPHT DP sensor in their subsea transmitter/flowmeter. In the end, only Solartron was able to dedicate the necessary resources to the project.

3. Details of Task Plan

The initial objective of Task 3 was to address these serious operational restrictions by identifying the sources of the pressure and temperature limitations in the most universally utilized sensors in multiphase and wet-gas flow meters. These sensors include those that measure pressure (P), temperature (T), and differential pressure (DP). Once these sensor technology limitations were verified, a program would be formulated to increase the operational environmental limits of these key sensors for use both in the flow meters and also at monitoring points along the subsea flow path, including at the wellhead.

This project was launched in November 2008, with the goal of identifying (or developing) and qualifying sensors for extreme high-pressure high-temperature (HPHT) service on subsea

multiphase meters, and for other subsea applications as needed. Early in the project, it became clear that HPHT pressure and temperature sensors were available commercially for subsea applications. However, a missing technology was the availability of an accurate differential pressure sensor for use in HPHT regimes. As a result, the JIP made the decision to modify the scope of this project to focus on the development and qualification of a differential pressure sensor (DP). To correct for line-pressure, an absolute pressure sensor was added to the development.

The approach taken was to develop HPHT sensor chips, and then test these chips in assembled cells. Subsea transmitter manufacturers would then integrate these cells into their housings. Finally, documentation would be provided to allow commercialization of the HPHT DP sensors.

3.1 Intellectual Property

Because significant new technology had to be developed in order to achieve the desired performance of the difference pressure subsea pressure transmitter, much of this new technology must be treated as intellectual property until either RPSEA or Letton-Hall Group decides whether to file for patents on it. The information contained in this report should be treated as confidential intellectual property, belonging to RPSEA, the Letton- Hall Group and members of the cost-sharing JIP for the 07121-1301 project.

3.2 System Requirements

- The DP sensor will be configured for use in a “remote-seal” configuration.
- Operating pressure will be 1.5 times full-scale (7.5 bar).
- Each side can withstand full test pressure (22.5k psig)
- Temperature (production fluids) ≥ 250°C
- Ambient temperature > -10° C
- Water depth >3000 meters (4.3k psig)
- The accuracy of the sensor is defined as the total uncertainty as a percentage of full scale. This is calculated as the square root of the sum of the squares of the linearity, hysteresis, and repeatability of the sensor over its operating range. For a ”smart” transmitter, the requirement is usually at least a maximum of +/- 0.1 percent.

4. Execution of the Plan

4.1 Technical Challenges

Developing an accurate differential pressure measurement device for the environment described in Section 3.2 presented the following technical challenges:

- Design & fabrication of HPHT DP silicon chip. The sensor chip must provide the needed accuracy over the entire range of operating temperature. In addition, the chip must be able to withstand exposure to the maximum rated temperature for indefinite periods of time.

- Packaging of HPHT DP silicon chip. Since the sensor will be placed in an oil-filled housing behind an isolation diaphragm, the design must accommodate the thermal expansion of the oil without undue back-pressure or stress on the silicon DP sensor sensor's diaphragm. In addition, the sensor must be protected from one-sided line pressure with no change in calibration, and finally, the design must provide for high line-pressure rejection (calibrating out the common-mode pressure).

- Packaging of sensor cell in transmitter housing. Each subsea flowmeter manufacturer utilizes a different technique for packaging the DP sensor in their unit. The HPHT design must be designed so that it can be adapted by these various manufacturers for their flowmeters.

- Design & construction of a test system for characterizing the prototype DP HPHT unit. In order to characterize the performance of the HPHT cell, a test system consisting of the following was required:

  » A dual dead-weight tester to verify the performance with a line pressure of greater than 20k psig
  » An oven that can accurately control the temperature of the cell during the testing
  » A dead-weight tester for testing the absolute pressure sensor in the cell

4.2 MEMS Technology

Several sensor technologies were investigated including capacitive, vibrating structure, and piezoresistive. However, past experience with similar transducers for the U.S. Space Shuttle program had shown that a piezoresistive approach had the highest probability of success.

Single-crystal silicon bulk resistivity changes under stress. A resistor can be fabricated from silicon (as well as other semiconductors) to exploit this phenomenon. Such a resistor is commonly called a piezoresistor. The Space Shuttle tire pressure sensors had a requirement to withstand a temperature of 500°F without shifting out of calibration. This high temperature is due to the transducer's close proximity to the shuttle brakes. A technology, as shown in Figure 1, was developed in which the silicon piezoresistors are isolated from each other and from the substrate by a silicon dioxide layer. The shuttle program sensors were processed so that they had an almost linear temperature dependence.[3]

Figure 2 shows a cross-sectional view of the fabrication of a piezoresistor as well as its packaging into a pressure sensor. Note the use of an insulating layer in this structure to dramatically reduce leakage currents which increase with temperature. Without the silicon-on-insulator (SOI) structure, it is extremely difficult to produce devices that would yield an accurate response over the required wide temperature range. Figure 3 demonstrates how a piezoresistor can be packaged in an oil-filled enclosure with an isolation diaphragm to form an absolute pressure sensor. Figure 4 extends the conceptual design to show how a differential-pressure transducer might be created.

Figures 1 through 4 are from the 1991 Instrument Society of America Symposium presentation[1].

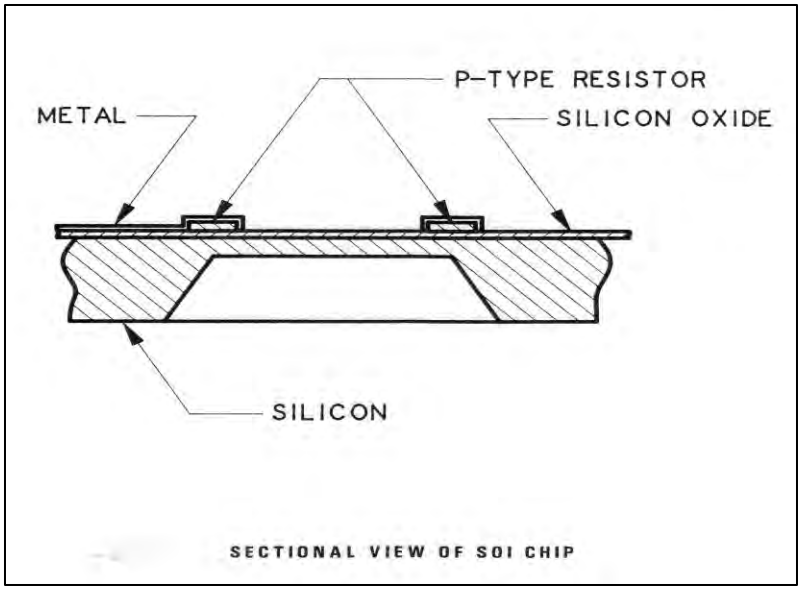


Figure 1. Typical Structure of a Silicon-on-Insulator Pressure Sensor

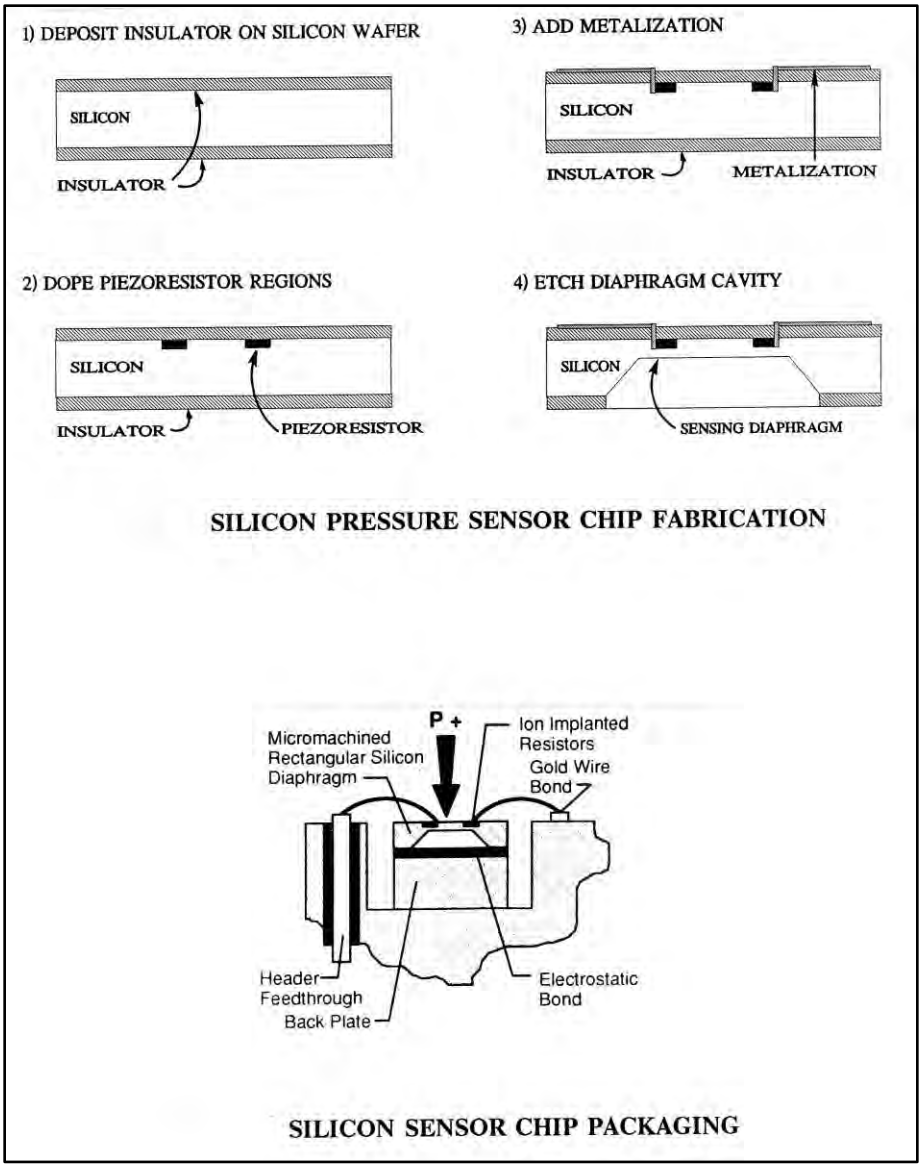


Figure 2. Silicon Pressure Sensor Chip Fabrication

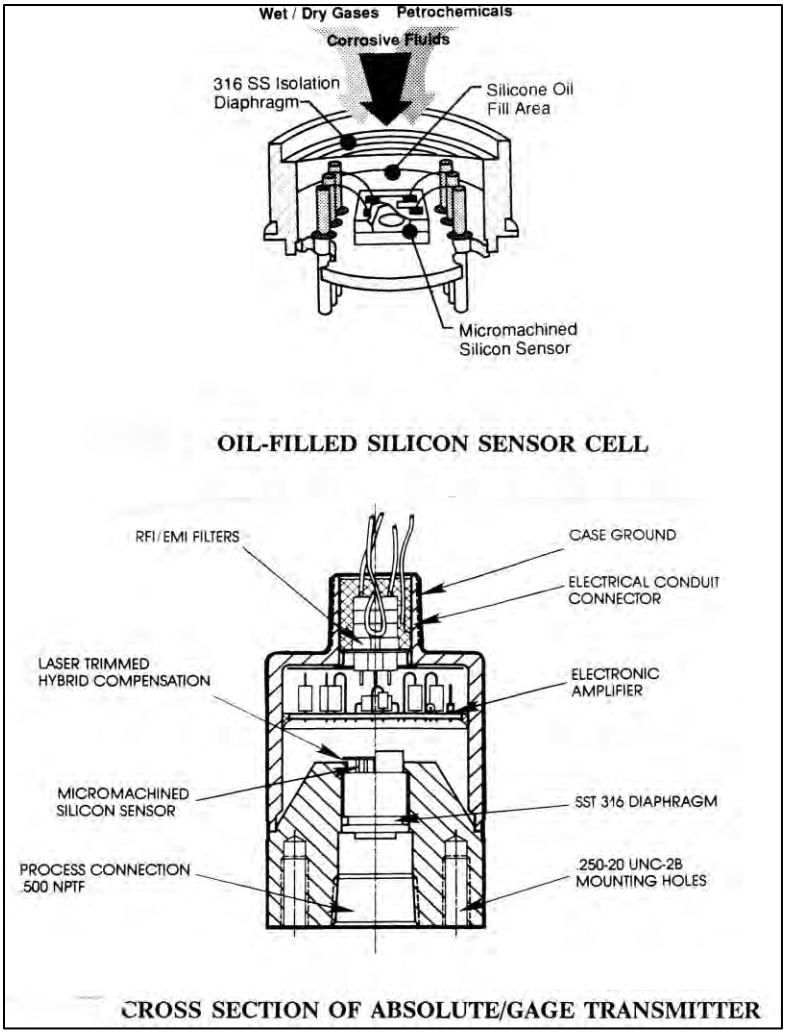


Figure 3. Cross section of an Oil-Filled Absolute Sensor

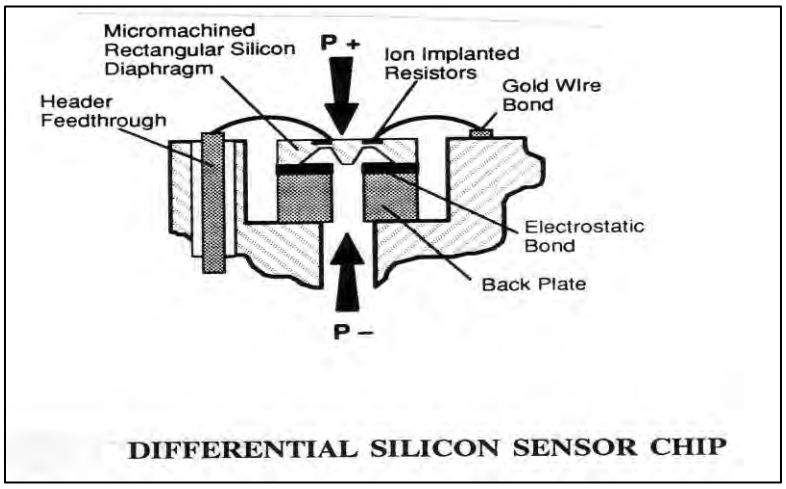


Figure 4. Differential Silicon Pressure Sensor

4.3 Piezoresistor Sensor Design and Fabrication

Axept LLC was contracted to design the differential and absolute silicon pressure sensors as well as the cell within which these sensors will operate. The direction they chose was based on previous work that showed silicon can provide up to 500 times overpressure protection[2]. They used the latest modeling tools to optimize the design and increase the overpressure capability. Finally, they used advanced processing capabilities which offer greater degrees of freedom in mitigating stress at edge of the diaphragm through shaping or sculpting. Figure 5 shows a diagram of the differential and absolute pressure sensors.

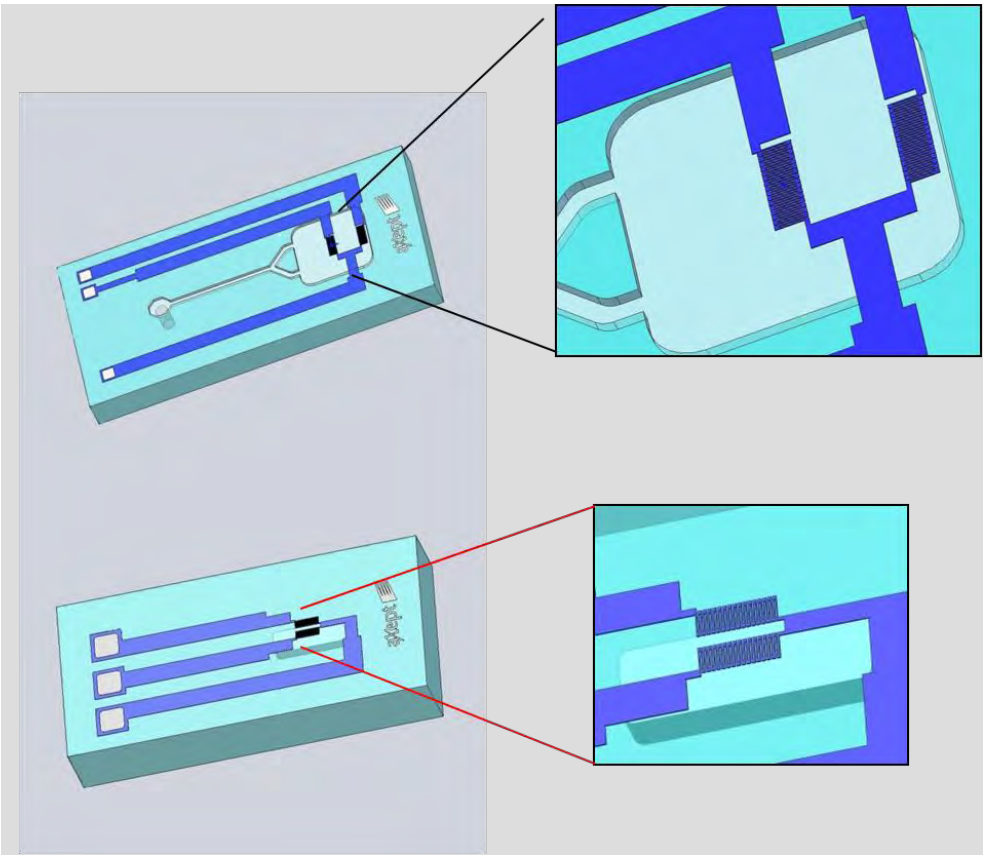


Figure 5. Differential and Absolute Sensors

The DP (6 x 3mm) and Absolute (3 x 1.5 mm) are co-fabricated on a single 4-inch diameter wafer which yields a maximum of 244 die sets per wafer. Figure 6 shows a photograph of one of the masks used in the fabrication of the wafer.

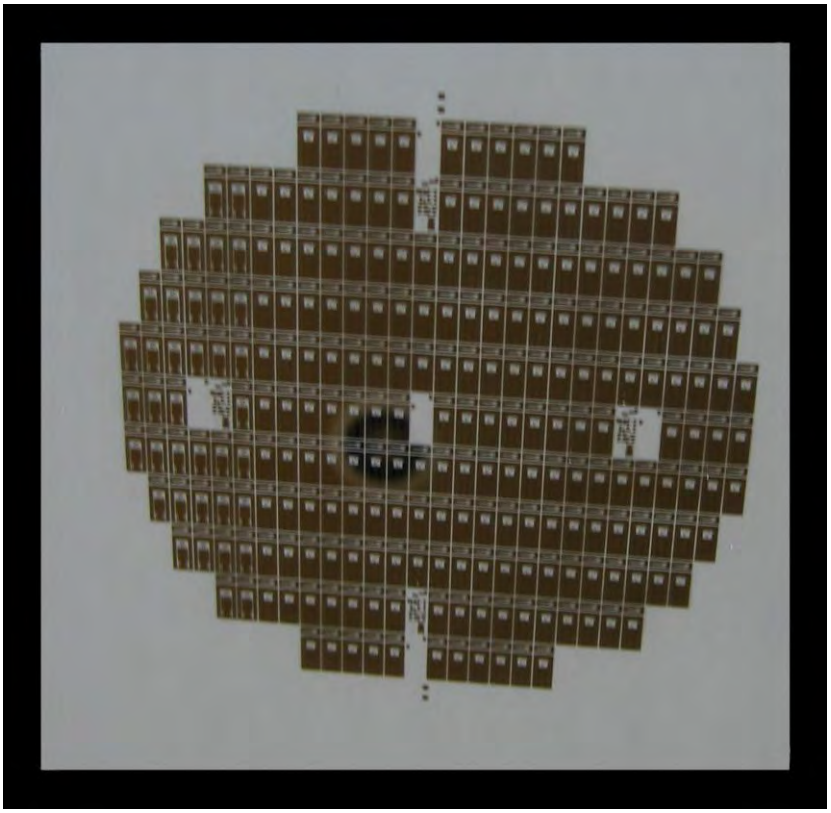


Figure 6. One of the Photo-masks used to fabricate the Sensor Wafer

The completed wafer is diced to separate the individual sensor die and they are stored in trays in preparation for probing, as shown in Figure 7. Not all of the die survive the dicing of the wafer.

Figure 7. Tray containing some Diced Sensor Chips

Figure 8 shows a photograph of both sensors resting on a US dime. The vendor chosen for actual wafer fabrication uses a triple-stack silicon-on-insulator (SOI) approach with buried cavities. This results in a less complex fabrication and provides super-precise diaphragm and piezoresistor layer thicknesses. Ohmic contact formation requires development of an intimate contact between the silicon surface and a bonding pad metal layer, with no interfering dielectric. In addition, the ohmic contact layer must be carefully chosen to ensure that the barrier height to silicon is as small as possible. Platinum silicide/Titanium/Platinum (PtSi/Ti/Pt) metallization was used to achieve the 250°C operating temperature specification. This yielded a contact resistance of less than 1.0x10-5 ohm-cm^2 at 25°C. The contact resistance remained acceptable after 4,000 hours at 250°C.

Figure 8. Differential and Absolute Sensors on a US Dime

The order form for the required three masks can be downloaded from:
http://rpsea.letton-hall.com/tiki-download_file.php?fileId=943

Detailed fabrication steps for processing the SOI wafers to produce the HPHT die can be downloaded from: http://rpsea.letton-hall.com/tiki-download_file.php?fileId=942

In order to evaluate the performance of the P and DP sensor chips, samples were mounted on TO-5 headers and pressure was applied. Figure 9 shows a sample of these chips mounted on the headers.

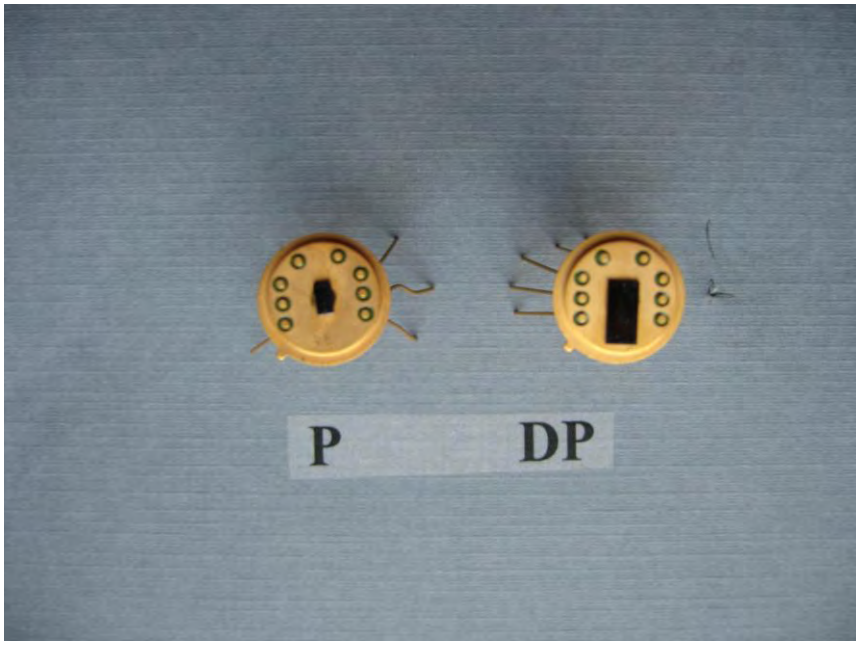


Figure 9. Sample of sensor chips mounted on the headers

One fabrication problem encountered during development was an etch phenomenon termed "footing" resulting in undercutting, affecting mostly piezoresistors on the absolute die. Footing can be seen in Figure 10. The absolute die employs line widths of 3.0 microns versus 6.0 microns for the differential die. Therefore, for a given amount of footing, the relevant effect on the piezoresistor cross-section is larger for the absolute die. The requirement for the deep reactive ion etch (DRIE) process is to etch through the silicon layer and stop on a buried silicon dioxide (SiO_2) layer. The anisotropy of DRIE depends on ions being accelerated vertically in the etch chamber. Footing is caused by accumulation of electrical charge on the buried, insulating SiO_2 layer, resulting in development of a stopping potential. This stopping potential reduces the ion energy, degrading anisotropy and allowing lateral etch or undercutting of the silicon. A solution to the footing problem was found by using fewer etch cycles and more passivation cycles. The results are shown in Figure 11.

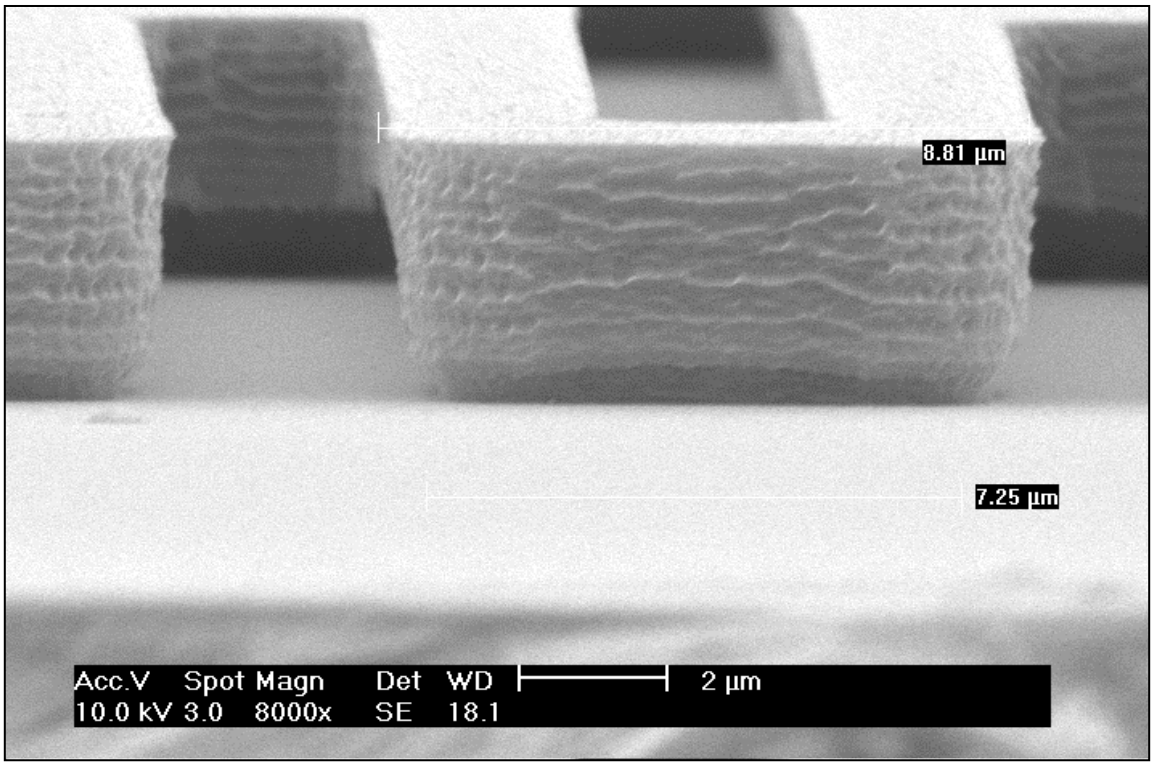


Figure 10. Scanning Electron Microscope Image showing "Footing"

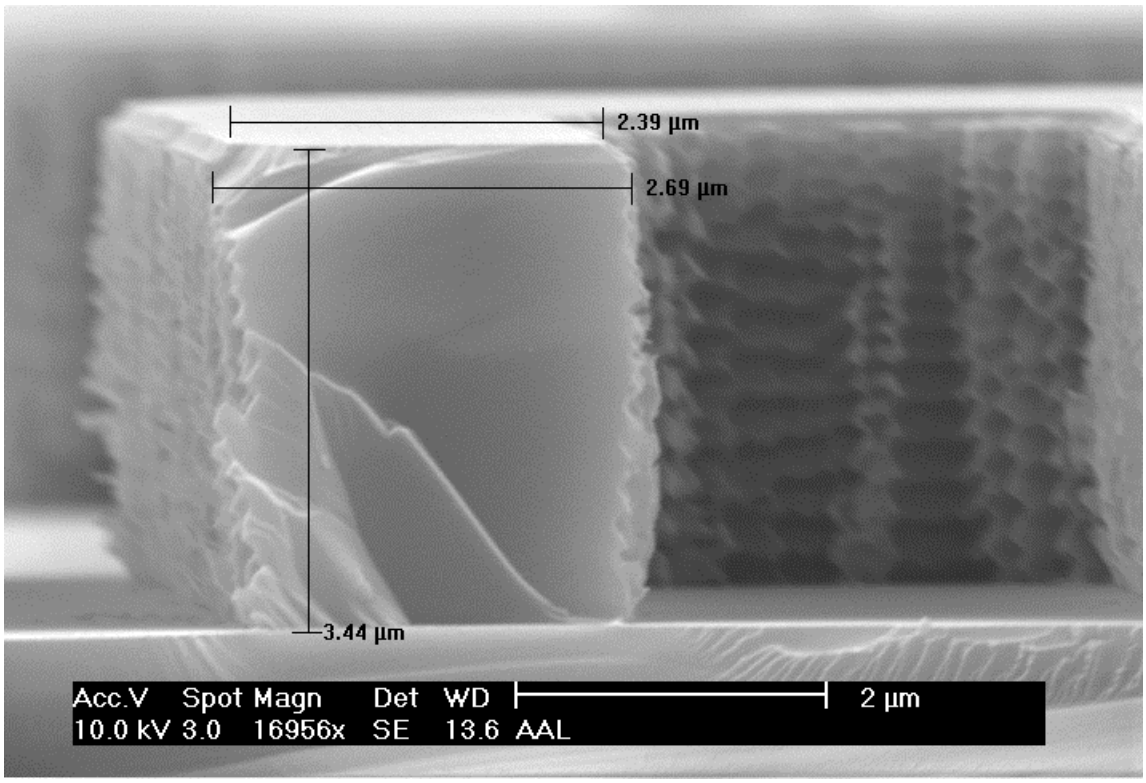


Figure 11. End-on view of a single absolute piezoresistor having 25 etch cycles. Note the almost complete absence of footing.

Figure 12 shows the header design and the ceramic spacer. The headers are only used for hermetic sealing and electrical feed-through. The die are not mounted directly on the header, which minimizes the diameter of the Kovar headers. By minimizing the diameters of the Kovar header and pins, this reduces the required strength in the mounting weld and is an advantage in withstanding higher pressures. *Axept* made

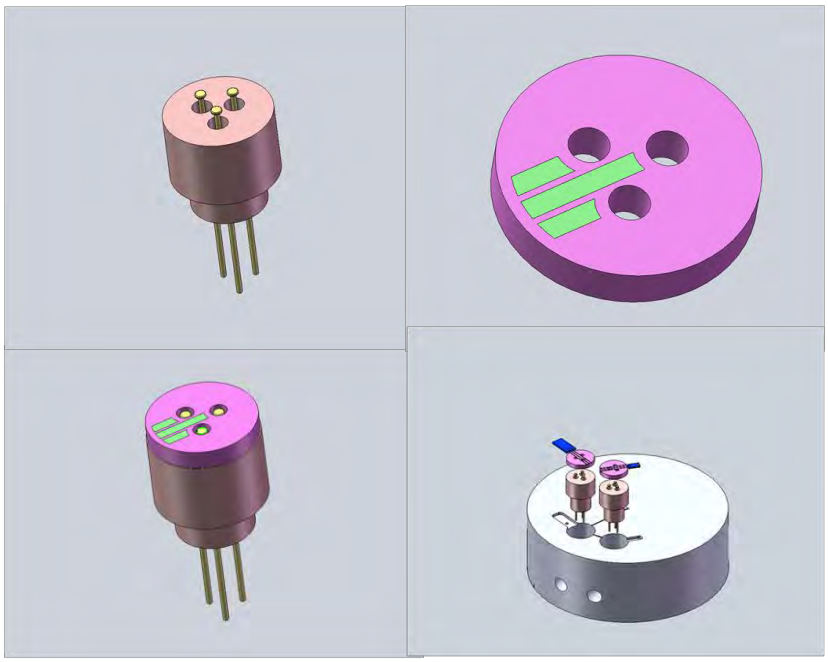


Figure 12. Header and Spacer Design

Finite Element Analysis (FEA) runs to ensure an adequate safety factor. The Ceramic Spacer was designed to reduce the oil volume. The metal pattern on the spacer allows for reduced wirebond length and height.

4.4 Differential Pressure Sensor Cell Design-Phase I

Figure 13 shows the first-pass design for the differential pressure sensor housing. In this design, the internal diaphragm deflects, displacing oil behind the isolation diaphragm. Overpressure protection is provided when this isolation diaphragm backstops against its mating face and no longer transfers pressure. The corrugated isolation diaphragm, shown more closely in Figure 14, is to be formed in-place. The internal diaphragm is placed into a recess in the center cell-body and is perimeter welded, and is also clamped against the low-side cell body upon assembly. The internal diaphragm is carefully designed to ensure normal operation at -10°C and at the maximum common-mode pressure.

The design specification requires full scale operation at 5 bar differential pressure at the two extremes of a) 250°C, zero common mode pressure (maximum oil volume) and b) -10°C, 20k psig common mode pressure (minimum oil volume). A third constraint is based on the decision to limit the internal cell pressure to between 20 and 25 bar, or four to five times the full scale pressure. (Based on experiments and further iterative modeling we may elect to lower the internal cell pressure at which the diaphragm is stopped in the future.) At high temperature, the limiting constraint is that the isolation diaphragm must stop against its backstop at more than 5 bar but less than or equal to 25 bar differential pressure. At cold temperature and maximum common mode pressure, the isolation diaphragm must be prevented from stopping against its backstop at full scale differential pressure. A model was developed to allow rapid determination of diaphragm deflection volume, edge stress, and backpressure as diameter and thickness are varied. Several model predictions with specific parameter combinations were validated through FEA to ensure accuracy. As the model was exercised, it became apparent that the various constraints can only be met when overall oil volume is minimized. In particular, a goal was developed to reduce oil volume to 0.1 cc or less.

To illustrate the design difficulty, the volume of a single drilled hole of 1.6 mm (0.063”) diameter through a 40 mm thick cell body amounts to 0.08 cc. It was therefore determined that drilled hole diameters must be restricted to 0.8 mm (0.032”). An in-depth discussion was held with a qualified

machinist to discuss this and other machining challenges. It was agreed that it is possible to drill the required 0.032-inch holes.

To achieve the goal of less than 0.1 cc oil volume, a critical decision was reached to place the silicon sensors within the central cell body, as opposed to remoting the sensors above the cell body as is usually done. An innovative design was developed allowing the sensors to be placed within the central cell body, with only electrical wires extending out the top of the cell body. Two design approaches, based on two-piece or three-piece cell bodies, were evaluated. Fabrication of a two-piece cell body requires off-center machining of critical cavities. Fabrication of the three-piece cell body is more compatible with conventional lathe operations, but an additional weld is required. After some study, the three-piece cell body design was chosen. With this approach, the headers, silicon die, and overpressure diaphragm are all assembled to a center cell body that is about 20 mm thick. High side cell body and Low side cell body each include an isolation diaphragm welded onto the face.

Since the interior face of the Low side cell body is flat, the piece can be as thin as 4 mm. The face of the High side cell body contains a recess, leading to the requirement for this body to be very stiff. With maximum common mode pressure applied to the isolation diaphragm the cell body can flex over the interior recess, engendering large shear stresses. Several FEA models were executed to evaluate these stresses. It was determined that the High side cell body must be at least 20 mm thick. With this thickness set at 20 mm, the current overall length of the assembled cell body is 44 mm.

Details of the materials used in the construction of the cell can be downloaded from:

http://rpsea.letton-hall.com/tiki-download_file.php?fileId=940

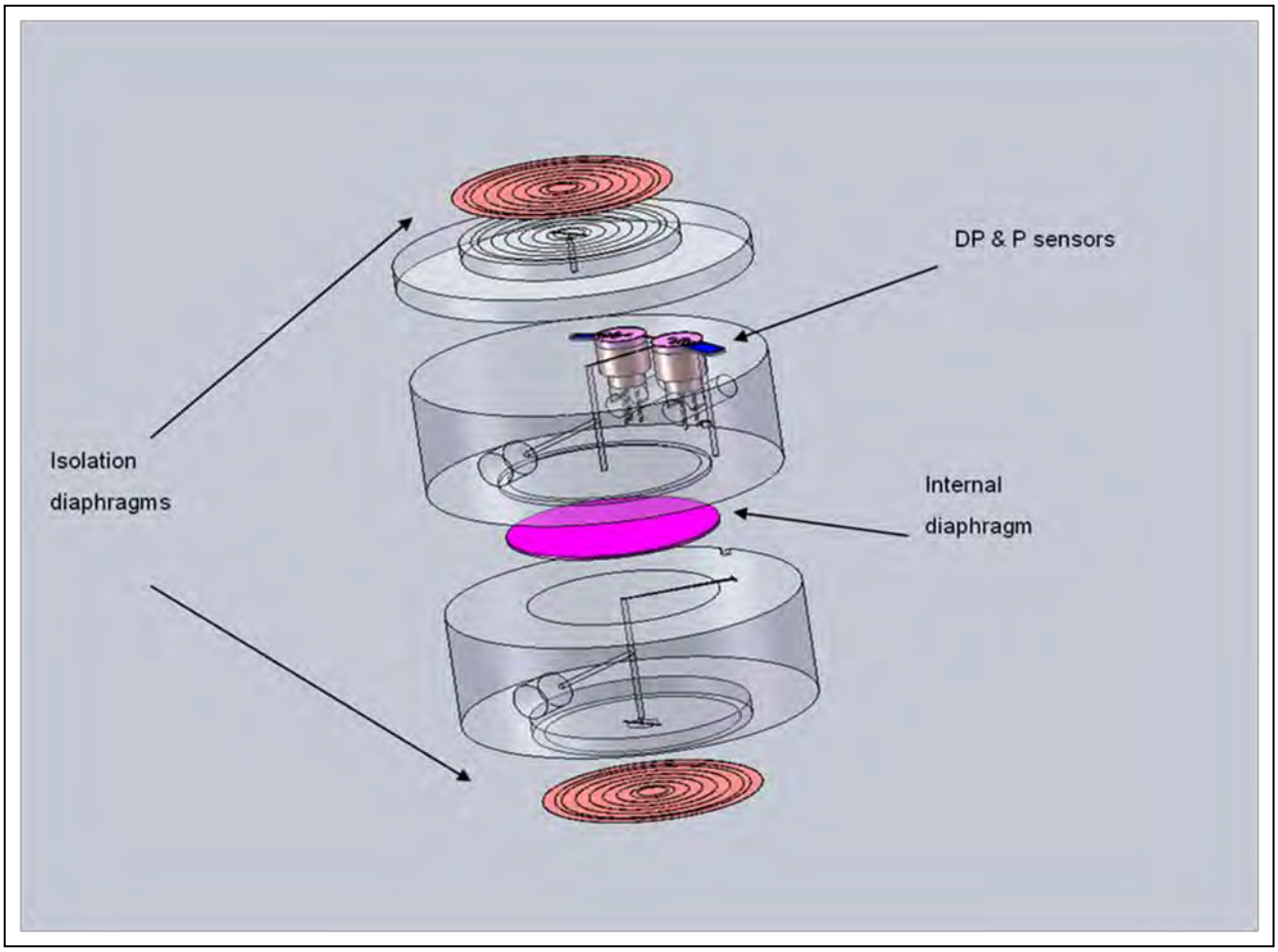


Figure 13. First-pass Design of Differential Pressure Sensor

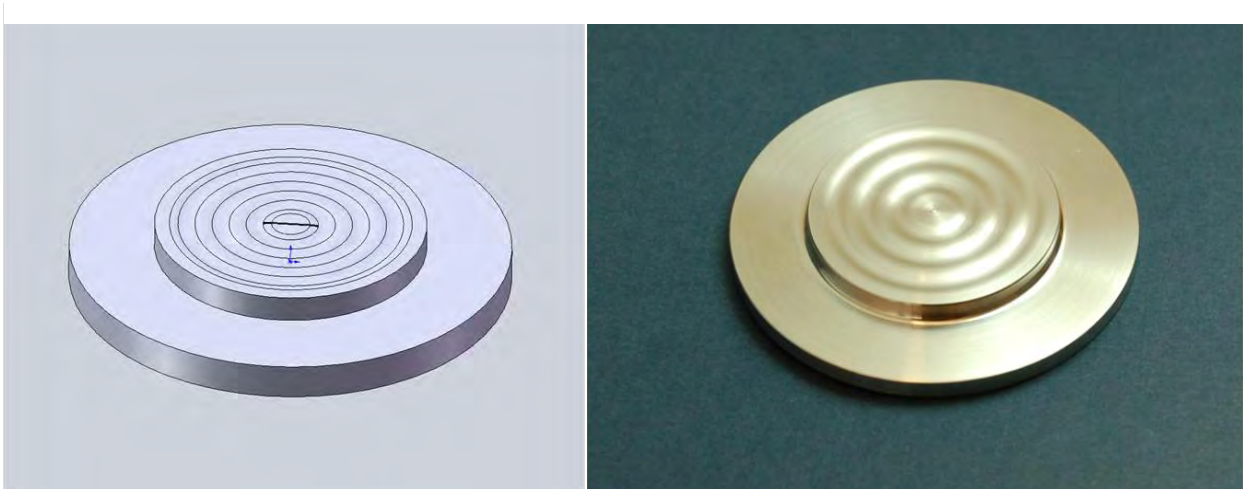


Figure 14. Isolation Diaphragm Design

The initial prototype, Cell A, was assembled and tested in the differential text fixture shown Figure 15. The cell responded slowly with applied pressure as shown Figure 16. The output voltage was measured as a function of time following the application of 75 psi differential pressure. An exponential fit was made to the data, with calculated time constant of 18 seconds. The 10 – 90 rise time was about 40 seconds, with 120 seconds required for the output voltage to stabilize to within 5 microvolts of the final value. Subsequent measurements were made at 37.5 psi, and with both positive and negative pressure. The time constant was essentially the same with these various conditions. Modeling was initiated to understand the variables involved in the time constant. When full-scale pressure of 75 psi is applied, 15 mm^3 of oil is transferred from behind the isolation diaphragm to the inner cavity. In order to minimize total oil volume, the cross-sectional area through which the oil is transferred was restricted by design. To reduce the response time, this cross-sectional area would need to be increased.

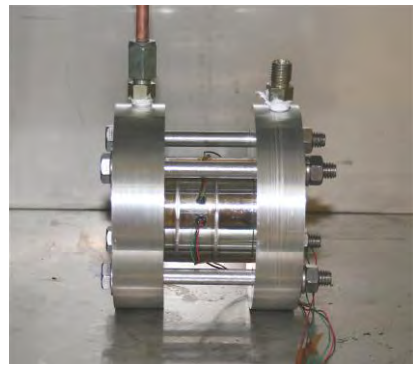


Figure 15. Cell A in Differential Test Fixture

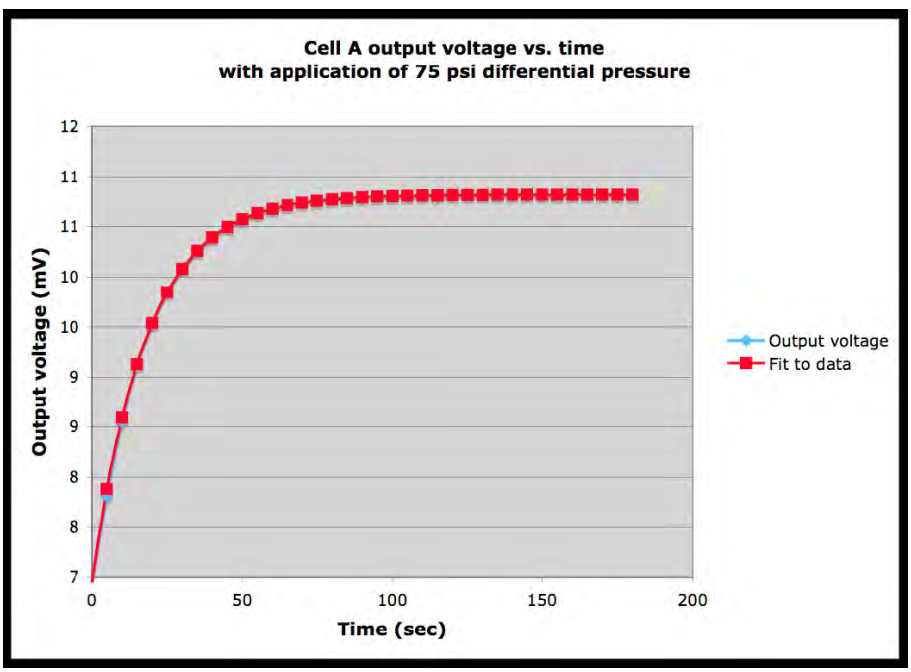


Figure 16. Cell A Output Voltage Vs. Time

The second prototype, Cell B, was assembled with both the differential and absolute die mounted and wire bonded. The cell was filled with oil and tested up to 200°C with excellent results, shown in Figure 17. Testing was conducted up to a common-mode pressure of 4000 psig, at which point one of the differential chip's output leads opened. Testing continued on the cell up to 250° C to confirm that there were no material issues with the design.

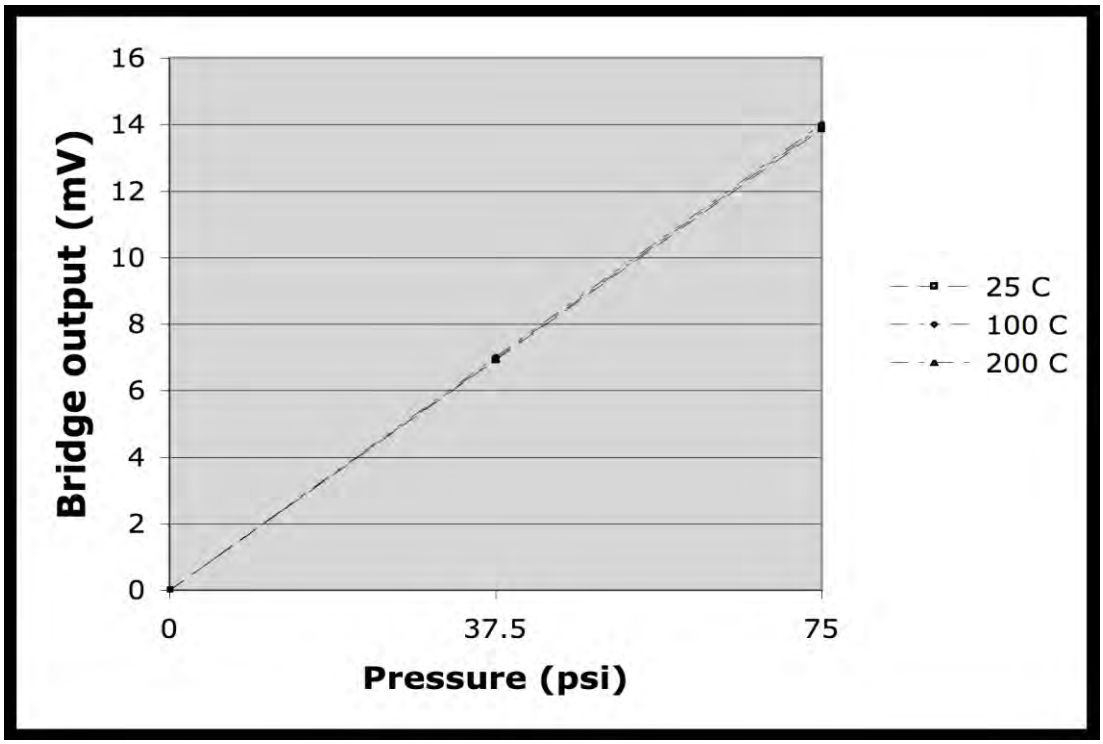


Figure 17. Cell B Response for Three Temperatures

Another problem that required considerable attention was overpressure protection. The cell design uses an internal diaphragm that deflects, taking up displacement in the oil which fills the cell. The design requires the isolation diaphragms to move to a backstop, which stops additional transfer of pressure. Initial testing indicated that overpressure protection did not work correctly due to excessive oil volume between the isolation diaphragm and its backstop. This problem was traced to thermal stresses being locked into the isolation diaphragm during the welding process. This problem was solved by use of a weld ring. Figure 18 shows the isolation diaphragm height versus radius. The goal is to have a good match in the width of the corrugations to the tool height. This figure shows a good match which should provide good overpressure protection.

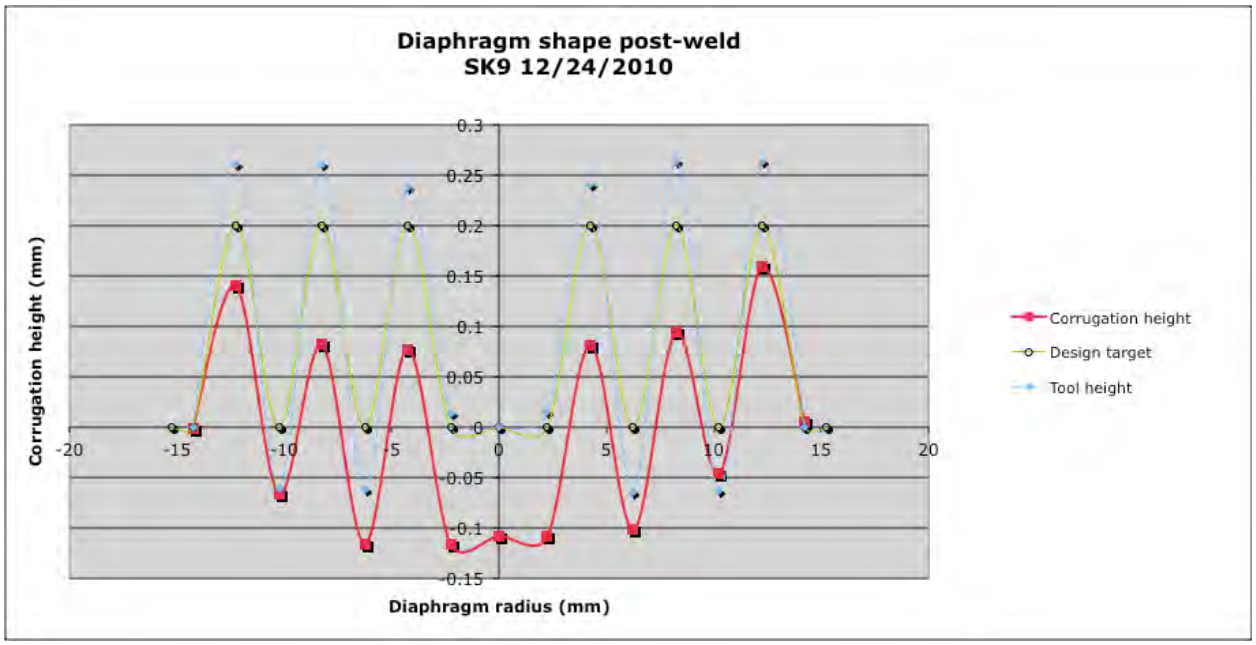


Figure 18. Isolation Diaphragm Height vs. Radius

4.5 Differential Pressure Sensor Cell Design-Phase II

Based on the results from the Phase I Sensor Cell Design, several improvements were initiated using the following guidelines:

- Reduce complexity of machined parts by:
  - Reducing parts count and number of welds from three to two.
  - Minimizing number of setups required for producing machined parts.
  - Simplifying machined diaphragm stop profiles.
  - Increasing drilled hole diameters.
- Balance force due to common mode pressure applied to end faces against an outward-directed internal force.
- Improve matching of oil volume between high and low sides.
- Reduce effects of internal diaphragm bow due to CTE mismatch.
- Position absolute and differential headers opposite each other rather than side-by-side.

An illustration of the improved cell design is shown in Figure 19.

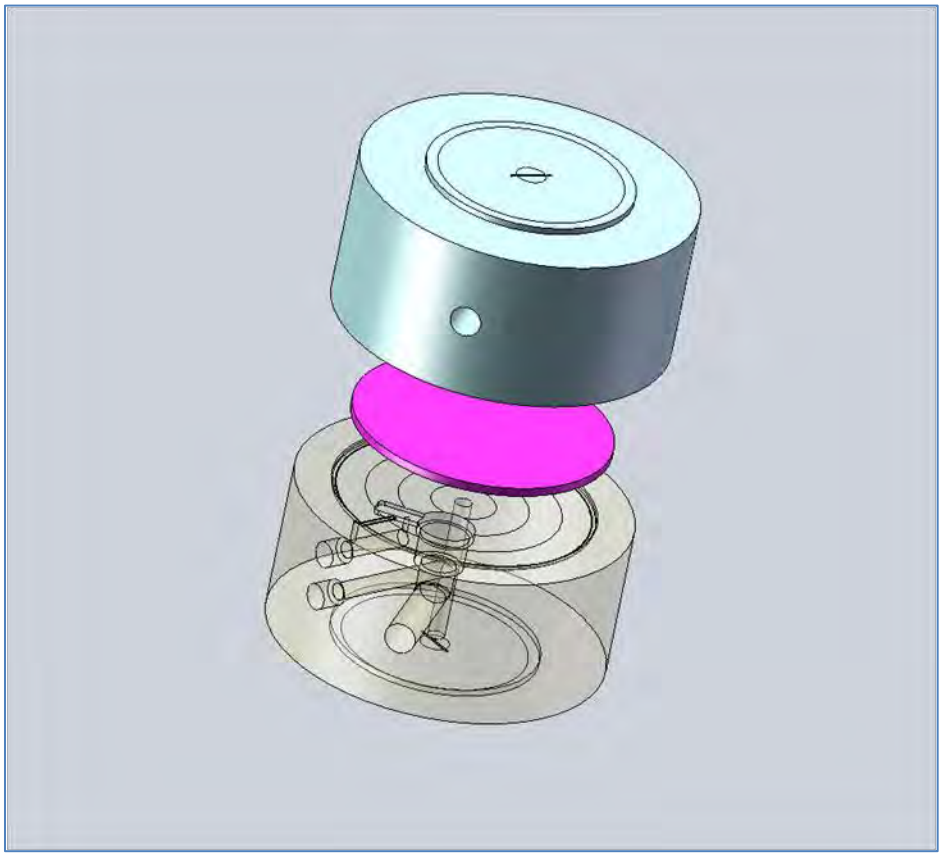


Figure 19. Phase II Cell Design

The assembled cell, ready for welding, is shown in Figure 20.

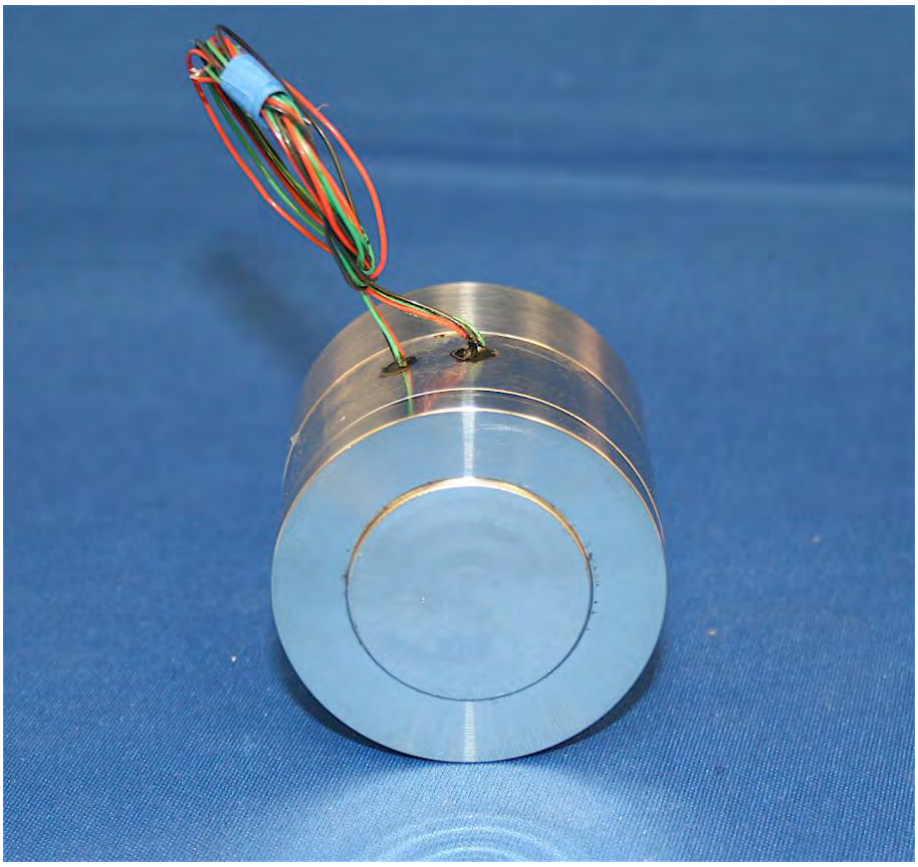


Figure 20. Fully Assembled Cell

The detailed drawings for each of the components of the cell can be downloaded from:

http://rpsea.letton-hall.com/tiki-download_file.php?fileId=941

4.6 Pressure Testing

For initial pressure testing the cells, three separate fixtures were required:

- Delta-P test fixture;
- Common mode test fixture;
- High common mode Delta-P test fixture initially capable to 5000 psi.

The completed test fixtures are shown in Figure 21.

Figure 21. Completed Test Fixtures

5. Results and Deliverables

5.1 Initial Testing at *axept*

Four assemblies were completed and tested. The results can be summarized as:

- Differential performance proven over 25 - 250°C and up to 150 psi (2X full scale)
- Very low common mode effect measured up to 4000 psig
- Excellent temperature compensation with only a gross first-order compensation
- Stability over time and temperature is excellent
- Results of the DP output as a function of temperature is shown in Figure 22.

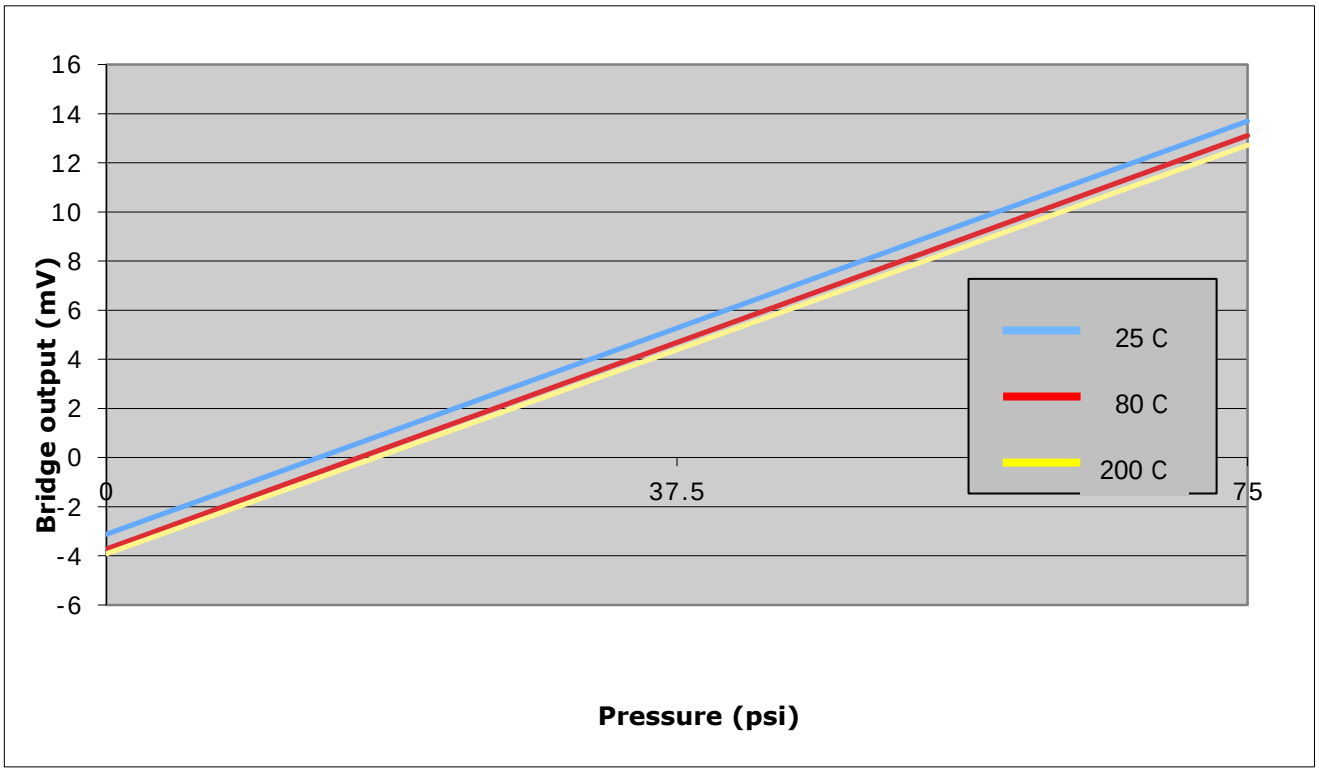


Figure 22. Initial test high temp Delta-P sensor

Note the linear response of the DP sensor, even though the cell had not been compensated for temperature shifts. This test also illustrates that temperature compensation will require only a simple first-order correction.

5.2 Testing at Solartron

Discussions were held with Solartron regarding the use of the cell in their wet gas flowmeter for subsea measurement. They agreed to participate in further testing of the completed HPHT cell. Solartron completed finite element analysis (FEA) and drawings for welding of remote paddles to the HPHT cell. A non-functioning cell has been shipped to Solartron in order to test electron beam welding of the remote paddles. Figure 23 shows a section of the test weld, which was certified to meet the standards.

Figure 23. Electron Beam Weld Test on HPHT Cell

Axept assembled the final two HPHT cells (C and D) for shipment to Solartron for final testing. Prior to shipment, they were characterized at the axept facility in Virginia. The 5 bar differential sensor (C) was calibrated at temperatures of 25, 100 and 150°C. It was perfectly linear at each temperature and the curves overlaid each other indicating no temperature correction was required over this range, as shown in Figure 24.

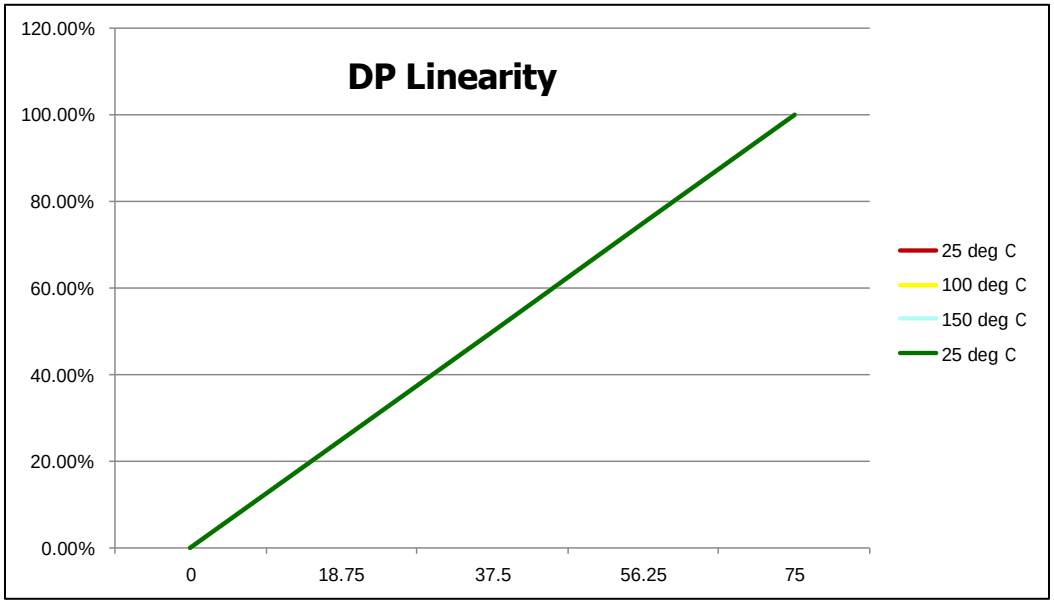


Figure 24. Linearity Calibration of HPHT Cell C at Various Temperatures

Cells C and D were packaged with their electronic boards as shown in Figure 25.

Figure 25. Cells C & D for Shipment to Solartron

Solartron sent Cell C to their vendor for electron beam welding of the end flanges needed for testing at Chamois Calibrations and for use in the Solartron subsea flowmeters. The completed assembly is shown in Figure 26.

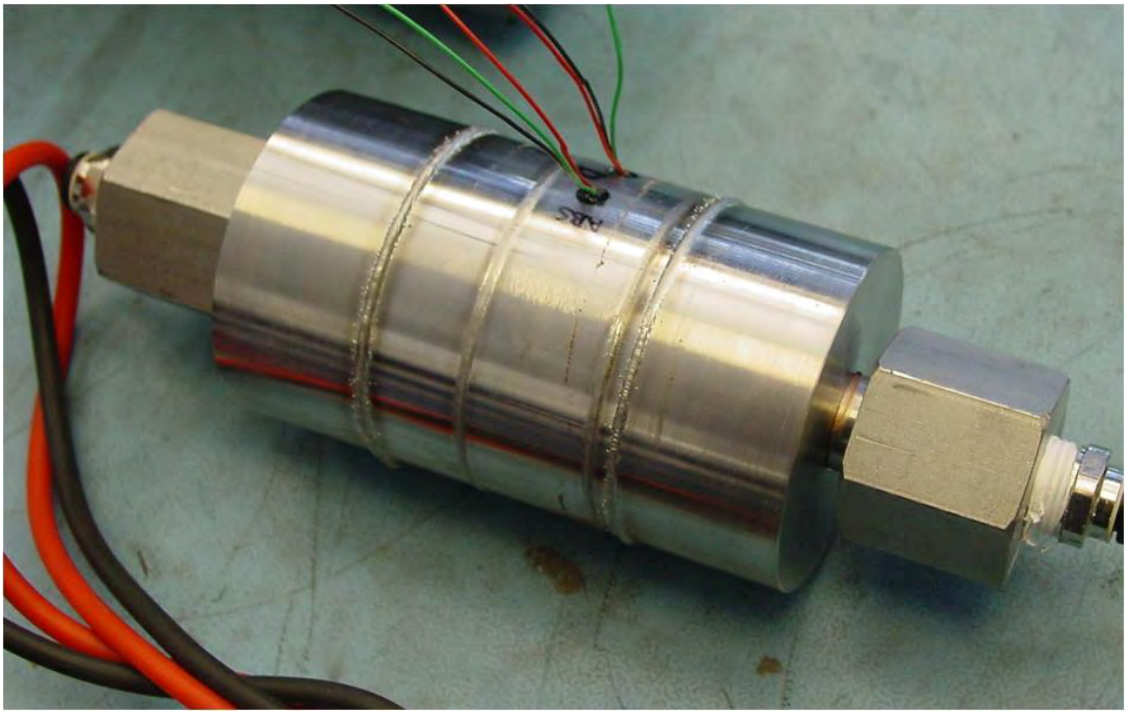
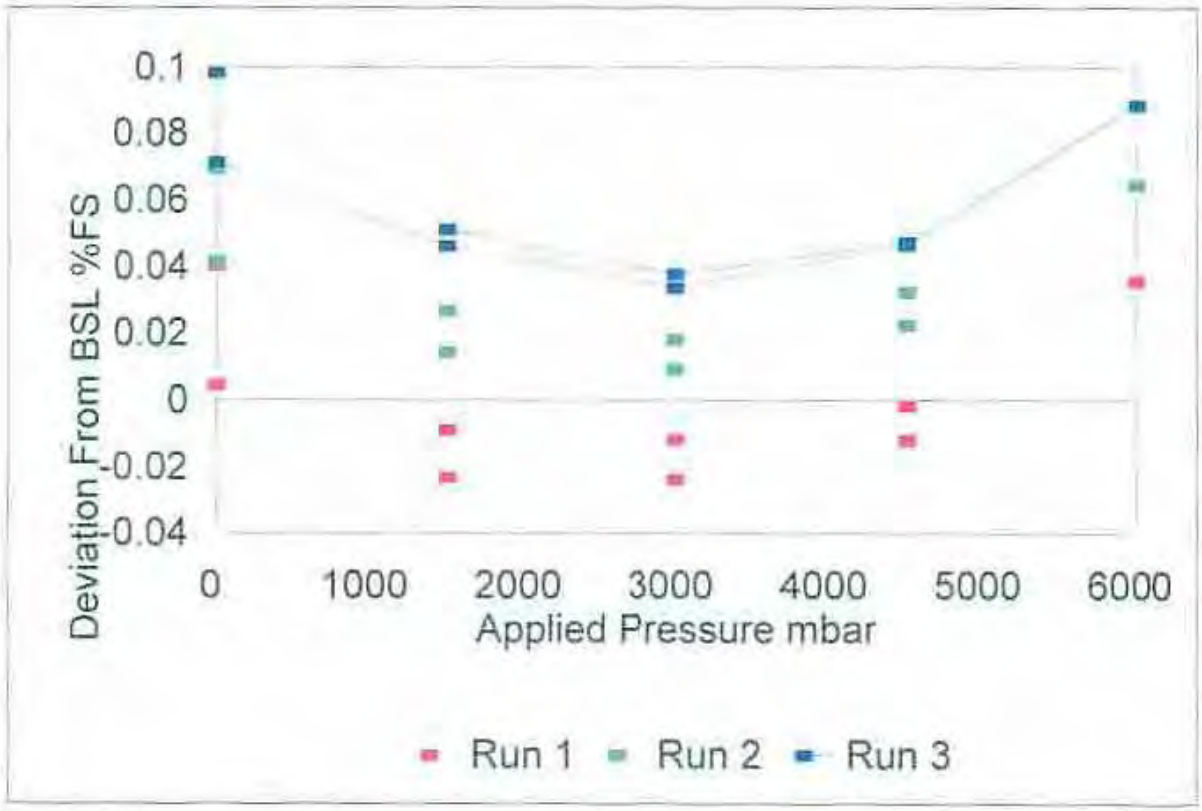


Figure 26. Welded Assembly for Testing at Chamois Calibrations

5.3 Testing at Chamois Metrology

The linearity calibration at Chamois Metrology was extended to 6 bar full scale. The maximum deviation from a best fit straight line was 0.07 percent. This was the result of three (3) calibrations, as shown in Figure 27. The common-mode pressure was 1000 psig during the calibrations. The certification for this calibration is shown in Appendix B. Details of the calibrations are contained in the Solartron Testing Report, which can be downloaded at:

http://rpsea.letton-hall.com/tiki-download_file.php?fileId=938



Best Straight Line (BSL) fit calculated by linear regression of Run 1 data

Figure 27. Linearity Data of DP Sensor at 1000 psig Common-Mode Pressure

The assembly was returned to Solartron for certification at 15,000 psig. This requires surviving exposure to 22,500 psig. Solartron conducted this hydrostatic test and certified the assembly to the specified pressure (see Appendix C). The assembly was then returned to Chamois Calibrations for linearity calibration at 15,000 psig static pressure.

However, the sensor failed to respond to the applied differential pressure and was returned to *axept*. Failure analysis indicated that the capsule lost its oil after being subjected to 22,500 psig common-mode pressure. The leak appeared to be at the plug in the oil-fill hole. The existing plug was removed, the cell was refilled with oil and the capsule was recalibrated to verify that the HPHT sensor chip's performance was not changed by exposure to 22,500 psig common-mode pressure. Figure 28 shows that the DP calibration was perfectly linear (R^2=1) when the differential pressure

was applied from either the high or low side of the capsule. This verifies that the HPHT was not damaged, since the overpressure protection of the capsule was effective.

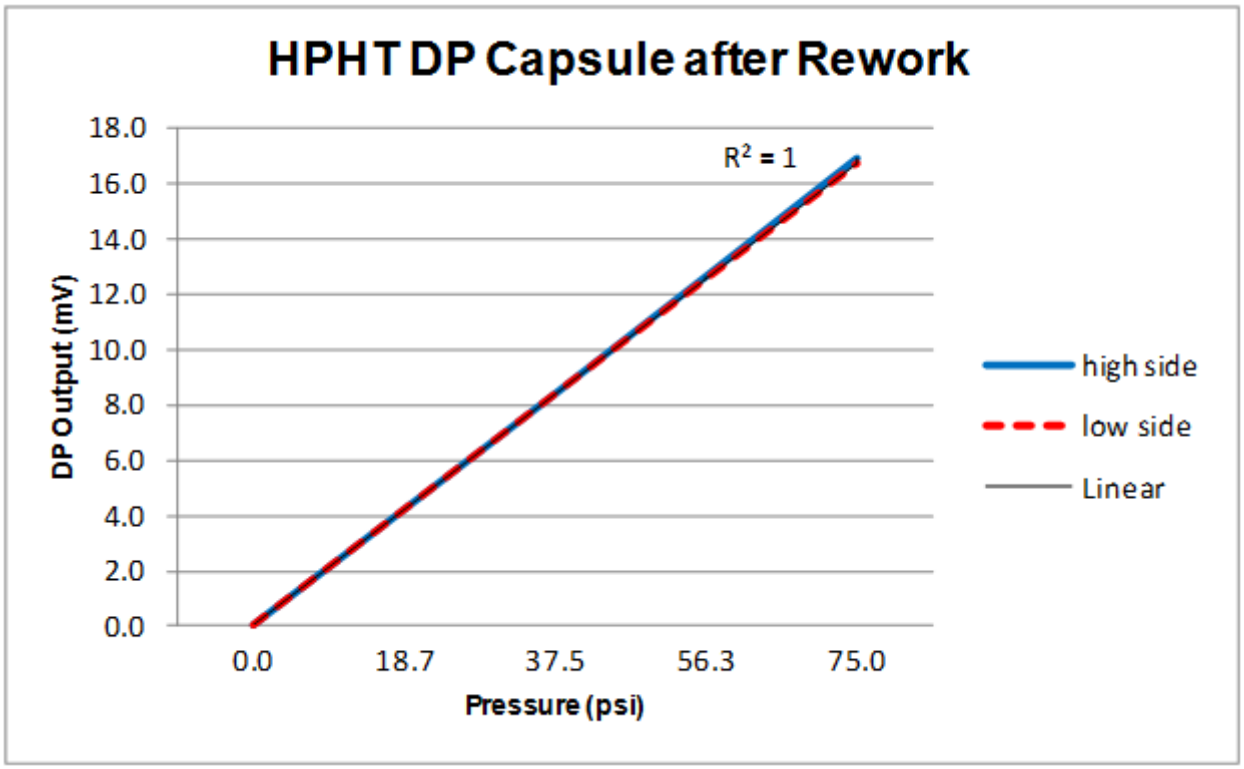


Figure 28. Linearity of Capsule Following Rework

The slight difference in output voltage shown for the DP sensor plots shown in Figures 22 and 28 is due to the change in electronics and compensation resistors for the calibrations.

6. Conclusions

Development of the HPHT DP cell for subsea use will expand the measurement capability in the newer offshore fields with HPHT production. The following conclusions should be noted.

6.1 HPHT Cell Developed

This development yielded an HPHT DP (5 bar) sensor capsule with the following performance:

- Linearity verified to 6 bar with a maximum deviation from a best fit straight line of 0.07 percent
- Differential performance proven over 25 - 250 °C and up to 150 psi (2X full scale)
- Very low common mode effect measured up to 4000 psig
- Excellent temperature compensation with only a gross first-order compensation
- Stability over time and temperature is excellent
- The overpressure protection of the capsule was effective in protecting the DP chip to 22,500 psig

6.2 Challenging Project

MEMS-based DP pressure sensors were first introduced commercially over 20 years ago. However, this is the first development of one that can operate at HPHT conditions. The primary reason is that the commercial market has not been large enough to justify the research and development (R&D) funds required. Many of the technical challenges could not be envisioned until they were encountered during the development of these sensors.

6.3 Significant Technology Developed

The primary justification for the development of the HPHT DP sensor cell was to allow subsea flowmeters to operate at the extreme production environments. However, now that the HPHT technology has been developed and verified, additional important ultra-deepwater and downhole applications can be envisioned. Of particular importance will be monitoring of production flow both downhole and along the flowline. This advance will give an “early warning” of unexpected flow conditions from specific zones. In addition, data from true DP sensors can benefit the increased use and performance of flow models (virtual flowmeters).

7. Areas for Continued R&D Investigation

There is a need to accurately measure well flow rate, not just at the wellhead but also downhole. The most common manner of measuring flow rate is through the use of a differential pressure measurement. While absolute pressure (P) sensors that can operate within HPHT environments are available, differential pressure (DP) sensors are necessary for these downhole measurements, and have not been available up to now. In the past, downhole DP measurements were made using two absolute pressure sensors, which introduce errors, especially in the case of large P and small DP. Fortunately, by utilizing the HPHT P and DP sensors developed in the current RPSEA 07121-1301 project, such a measurement system can be developed and demonstrated for downhole use. While such a measurement capability would greatly enhance normal production operations measurement, it might also be beneficial in early detection of a well inflow event before it could be sensed by other traditional methods, such as comparison of flow rates in and out of the well. This could be performed downhole, at the sea floor, or at intermediate points (e.g., zones) in the well.

To achieve this goal will therefore require developing the packaging of this HPHT DP-P sensor, then organizing and supervising a program among manufacturers for prototyping and testing the units.

More than 300 sets of sensor chips remain. These can be used in a follow-on project and/or by selected manufacturers to fabricate additional subsea DP transmitters. Complete documentation and the masks required to fabricate additional HPHT chips are being stored by the RPSEA Project 07121-1301 subcontractor.

8. References

[1] Hall, J., Micromachined Silicon Sensors for Pressure Measurements, ISA Edmonton '91 Symposium, Edmonton, Alberta, April, 1991.

[2] Christel, L., Petersen, K., Barth, P., Pourahmadi, F., Mallon, J. Jr., Single-crystal silicon pressure sensors with 500x overpressure protection, Sensors and Actuators, A21-A23, 1990, pp. 84-88.

[3] Hall, James E., Miller, Mark, Kliman, Robert, Sensor Redundancy for Critical Pressure Measurements, 37th International Instrumentation Symposium, I.S.A., San Diego, CA, May 1991.

9. Acknowledgements

The author would like to acknowledge the roles played by the two major sponsors. First, the U.S. Department of Energy, through its RPSEA unit, provided the funding and the impetus for numerous deepwater technology developments, including this one. And second, the member companies of the Joint Industry Project for 07121-1301 provided the co-funding required by RPSEA, as well as the expertise in subsea engineering and measurement necessary to successfully do the work.

In addition, the author acknowledges the valuable contribution of the subcontractor for task 3, *axept* LLC, in the design and fabrication of the HPHT die and capsule and the testing of the capsule by Solartron ISA.

Appendix A: Discussion of Budget, Finances.

Area	Budget	Actual
Organize JIP, complete gap analysis, define Task 3 specs (LHG)	$65,000	$7,706
Contract for design & fabrication of HPHT sensor elements	$399,889	$345,133
Packaging & testing of prototype sensor packages	$170,000	$137,534
Development of testing procedures & test systems	$45,500	$27,421
Project Management, Monthly Reports, Presentations, JIP Relations, Publications, Final Report	$92,361	$76,383
TOTAL	**$772,750**	**$594,177**

As indicated, this development was completed for a cost of nearly $180k less than budgeted. It was anticipated that additional iterations on the sensor design and fabrication might be required. Also, additional testing of the prototype capsules simultaneously at both the HP and HT extremes was planned. However, a suitable facility was not found in the United States or Europe. Therefore, separate testing at HT and then at HP was the alternative (less costly).

Appendix B: Certification from Chamois Calibrations

Chamois Metrology
Instrumentation Calibration Measurement Engineering

CERTIFICATE OF CALIBRATION

ISSUED BY: CHAMOIS METROLOGY LTD
DATE OF ISSUE: 15 September 2011
CERTIFICATE NUMBER: 10815

UKAS CALIBRATION 0822

Chamois Metrology Ltd
Unit 8 The Centre
Holywell Business Park
Northfield Rd, Southam
Warwickshire. CV47 0FP
Tel: 01926 812066
Fax: 01926 813569
e-mail: lab@chamois.net
www www.chamois.net

APPROVED SIGNATORY
✓N A Morgan
B. Hemple A Garthwaite

CUSTOMER DETAILS	Company	:	Solartron ISA
	Address	:	Hackworth Industrial Park Shildon County Durham DL4 1LH
	Order Number	:	PO-012142
UNIT CALIBRATED	Date calibrated	:	15 September 2011
	Calibration site	:	Chamois Metrology Laboratory
	Manufacturer	:	Solartron
	Model	:	Prototype DP
	Calibrated range	:	0 to 6000 mbar
	Static Pressure	:	1000 psi
	Serial No	:	5201/D
CALIBRATION PROCEDURE		:	PROC-32;21
ENVIRONMENT TEMPERATURE		:	20°C ± 2°C

Basic Measurement Method:
The unit under test was calibrated against a reference pressure balance.

Customer Requirement:
UKAS Certification.

TRACEABILITY STATEMENT
All measuring equipment used for calibration purposes is traceable to National or Internationally recognised standards.

Certified By:

Appendix C: Certification from Solartron

solartron ISA

HYDROSTATIC TEST CERTIFICATE

SISA Job No:	**IDRN 27**	**Client:**	RPSEA
Tag No.	5201/D	**Client Part No.**	N/A
Date of Test:	**21/09/11**	**Test Location:**	SHILDON

Test Equipment (Section 4.0)		
Item	Serial No.	Calibration Date
Pressure Gauge	82274002	19/09/11
Chart Recorder	BUK 11329	19/09/11

Pre Test Checks (Section 4.0)		
Activity	Drawing Number & Rev	
Assembled correctly		Yes
End flanges fitted/ports sealed		Yes
All connections correctly torqued		Yes

Test Medium	Inhibited Water

Hold Pressure Test Record (Section 5.3)				
Tag/Serial Number	Test Pressure (bar)	Duration (mins)	Operator	Pass/Fail
5201/D	1551 (22500psi)	60	G.D.	Pass

Comments:-		
SISA Test Supervisor GDawson Print Name:G.Dawson	Witness for Client Print Name:	Witness for 3rd Party Print Name:

RPSEA

Evaluation of Flow Modeling Final Report

07121-1301-Task4.FINAL

Improvements to Deepwater Subsea Measurement

07121-1301

September 20, 2011

Eric Toskey
Vice President, Exploration and Production
The Letton-Hall Group
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Houston, TX 77079

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Abstract

This report documents a project to improve subsea flow measurements to allow the flow rates of individual wells to be known more accurately. Because production revenues are determined from flow rates, improved flow measurement reduces the financial risk to stakeholders, including producers and the U.S. government. Improved measurement also helps to improve reservoir recovery. In this project, commercially available flow models were evaluated for their suitability as virtual flow meters, to augment or replace hardware devices for the determination of flow rates in deep water wells. The goal of this project was to develop methods for evaluating flow models, and to report on the efficacy of these models to predict flow rates. Several flow models were used in the study, which also includes a survey of the available models.

Prepared by:	Approved by:
Eric Toskey (LHG)	
	Date: September 20, 2011

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1. Introduction

1.1 Description: What is a Virtual Flow Meter?

Virtual flow meters (VFM) are a method for determining the flow rate of a well by means of modeling the flow. A VFM model may consist of a single well to an entire field of co-mingled wells. The models are fed data from sensors installed at various measurement points (nodes). Typically pressure and temperature sensors are used, which are available downhole (perhaps at multiple points), at the wellhead, and at the surface. With the pressure and temperature data at each node provided as an input, the VFM model computes the flow rate of the well. Typically, the model is tuned periodically using available flow data. Once tuned, the model is capable of determining the well flow rate with only the pressure and temperature nodal data. The flow models employed with VFM systems may be built from first principles, but this is not the only method for VFM modeling. Flow models may also be derived from statistical analysis of measurements acquired at different nodes along the production system.

An important observation is that VFM software is not something that must be installed at the same time as the physical multiphase flow meters, as long as care is taken to install proper sensors to be used at the various nodes. The fault tolerant nature of the VFM system is an advantage, since a failed "hard" sensor will reduce the number of nodes, but will not cause a complete loss of information.

While VFM technology appears to be maturing rapidly, it is not yet generally accepted an equivalent replacement for good physical metering. VFM models are employed as a back up to a physical meter to be used in case the primary metering system is unable to function, or as an augmentation of physical metering to reduce measurement uncertainty.

Some of the commercial VFMs use the technique of Nodal Analysis for the flow rate prediction. This method utilizes available transmitters (pressure and temperature) and a mathematical model of the complete flow path from bottom hole to the topside facility. This method requires considerable input data, including well and pipeline profiles, the diameters of all components of sections, sensor locations, fluid properties, choke geometry, etc.

Unfortunately, not many studies have been published which critically evaluate the performance and accuracy of available VFM's for subsea systems, although evaluation of some the VFM components may have been done privately. This can be carried out by comparing the predictions of VFM's with measurement data from actual subsea multiphase flowmeters or other physical measurement methodologies. Also, once such evaluations are documented in publications, positive results will encourage and justify the use of VFM systems.

1.2 Project Motivation

While VFM technology appears to be maturing rapidly, unfortunately, very few studies have been published that critically evaluate the performance and accuracy of commercially available VFM products for subsea systems. This hinders the utilization of the VFM by the industry.

UDW 07121-1301 Task 4 aims at addressing this gap in documented studies of current VFM technology. The critical performance evaluation of existing VFM's was carried out by analyzing the predictions of the VFM's over a range of conditions, and referenced to a simulated data set. As future evaluations are documented in publications, positive results will encourage the industry to utilize the VFM technology in monitoring or allocation applications.

In the evaluation of current VFM systems over a range of multiphase flow conditions, the objective was to identify areas of strengths and weaknesses. By documenting where existing VFM's can function, boundaries could be established on their use. By categorizing the operating regions where the existing VFM's need enhancements, this Task provides guidance to future needed developments to extend the operational envelope.

This project provided a critical evaluation of the performance of commercially available VFM's against reference data. This enables the industry to identify the operating conditions of applicability of VFM's and utilize them with more confidence due to improved performance. An additional incentive was the regulatory authority acceptance of the use of VFM systems, both for fiscal allocation as an acceptable verification method and a backup to physical subsea flowmeters.

2. Organization

2.1 JIP Task Group

The Task Group's role is to provide technical guidance and expertise for the task. The Task Group members act by consensus to ensure task activities remain relevant to industry needs and are achievable. The Task Group consists of interested persons who are employed by the JIP member companies. Usually these persons are experts in their field, and have an interest in production flow modeling. The Task 4 Group consisted of 22 persons from all 7 JIP companies, the lead sub-contractor, Multiphase Systems Integration, LLC (MSI), and the Letton-Hall Group

2.2 JIP Task Champion

The Task Champion's role is to provide direct technical guidance as well as leadership for the task group. The Task Champion is a recognized expert in the field of production flow modeling and virtual flow metering. The Task Champion from the start was Dean Wade of BHP Billiton. In June 2009, approximately eight months into the project, Dean left BHP's employment and resigned as Task Champion. The Task Champion role was taken over by Thomas Danielson of ConocoPhillips and Carlos Avila of Chevron.

2.3 Task Manager

The Task Manager's role is to organize and coordinate all task activities and finances, to interface with the Task Champion, contractors, task group members, and vendors, and to generate reports on progress as well as interim and final technical and financial reports. The task manager initially was Jim Hall. Eric Toskey took over the task management in May 2009.

2.4 Sub-contractor

The lead sub-contractor's role is to prepare geometry and configuration file, generate the simulated reference data, post input data, retrieve and analyze simulation rounds output data, interact with the VFM suppliers, assist in generating the evaluation protocol and product survey, and provide general technical guidance to the evaluation project. Multiphase Systems Integration, LLC (MSI) was lead sub-contractor. MSI is a Tulsa-based consulting engineering firm which specializes in three phase flow in process facilities, with particular expertise in flow modeling, as well as reservoir modeling. The lead engineers on Task 4 from MSI were Eduardo Pereyra and Jose

Gamboa. During the last few months of the task Mehmet Karaaslan took over from Eduardo and Jose. Ram Mohan was the primary coordinator for MSI's activities in Task 4 throughout the project.

3. Details of Task Plan

3.1 Objectives

The objectives of this task are to:

(1) Organize and define a detailed task plan to examine the various production system flow modeling methods, and determine their effectiveness for use as VFMs. Currently available commercial virtual metering systems will be included in the study.

(2) Identify, analyze and publish a survey of flow modeling methods. Develop one or more qualifications method(s) for validating the performance of each modeling method over the projected range of operating conditions and analytically test each available VFM system.

(3) Generate simulation data sets using suitable software protocol based on previously defined geometry and field configuration, and establish a metering database. Run the simulation data through the candidate flow models to examine limitations of the models over the projected range of operating conditions and quantify accuracy limits.

(4) Deliver the final report and presentation, including recommendations for use of current technology and for areas of future enhancements.

3.2 Framework

The JIP is the source for any field information, such as well geometry, used in this Task. Reference data is generated using a commercially available transient flow model to simulate the flow using the geometry and field configuration provided. An evaluation criteria is developed that will be utilized to validate of the performance of commercially available VFMs by testing their predictions against the reference data. JIP members were encouraged to provide data from subsea sensors that can be input into the selected VFM systems for the evaluation. In addition, existing operating subsea systems, instrumented wells and flowlines with multiphase meters, were sought for "live" testing of the VFM's.

Most of the commercial VFM software systems were made available by the suppliers for use in the evaluations. It was not necessary to purchase any software licenses using RPSEA funds. Nominal funds are budgeted to acknowledge the time required by these companies to setup and "tune" their VFM's for the selected applications. **NB:** ***The purpose of this Task is not to rank the performance***

of the systems from the different suppliers, but to evaluate the flow modeling systems with regard to their applicability for use in various subsea monitoring, verification and allocation applications.

Development and application of methods to benchmark the selected flow modeling methods and criteria for evaluation of several commercial VFM systems have been carried out. The subcontractor presented the reference data from a well(s) and VFM simulation data for evaluation over a range of operating flow conditions.

3.3 Deliverables

The deliverables of this task are:

(1) A flow model evaluation protocol as a method to examine the various production system flow models to determine their effectiveness for use as VFMs.

(2) A survey of flow modeling methods.

(3) Quantified results of a comparison of output data from candidate flow models over a range of operating conditions, with simulated field data provided as reference.

(4) A final report and presentation, including use recommendations and limitations of current technology, and areas for future enhancements.

The deliverables 1 – 3 are included in the final report, deliverable 4.

4. Execution of Plan

4.1 General Discussion

This task set out to examine flow models to make the industry's first independent evaluation of their use as virtual flow meters (VFMs). There are many aspects to cover in an evaluation of VFMs. A thorough evaluation of VFMs may include evaluating not only hydrodynamic and thermodynamic modeling, but also hydrocarbon phase behavior, viscous flows, wet gas and multiphase flows, uncertainty terms handling, input error detection, reproducibility when sensor loss occurs, performance under artificial lift conditions, and large scale field modeling when VFMs are applied to hundreds of producing wells in a commingled configuration. In addition, a thorough evaluation of VFMs requires time, because it is the performance of a VFM with or without very little intervention over as long a time as possible that is of most interest to operators. The JIP and Task Manager realized that this task, given its budget and time frame, could not make a complete and thorough evaluation of all of these aspects of VFM modeling.

The task set out, therefore, to address basic questions about VFM performance, such as:

- How do commercial models differ; how are they the same?
- What is the expected range of uncertainty and bias for flow rate predictions from a VFM?
- How well do VFMs model gas condensate or wet gas wells? Heavy oil wells?
- How do flow rate predictions improve with additional P, T measurement points along the flow path?
- Are some sensor data more important than others, such as temperature versus pressure?
- Is flow meter data necessary, or can VFM be used where no flow meters exist??
- What is expected or necessary to train VFM models? How frequently is training needed?
- Can a VFM be applied outside of its training data set?
- Are there a minimum number of sensors required for a reasonable VFM performance?
- Can VFMs detect when erroneous input data is provided?

The task plan was composed to address these questions by making a comparison between VFM simulations and reference field data. The VFM results would be analyzed collectively to draw conclusions about the technology as a whole, and not on an individual product basis.

4.2 Reference Data Generation

The critical performance evaluation of existing VFMs was initially intended to be carried out primarily by comparing the predictions of the VFMs with actual field data from subsea multiphase flowmeters or other measurement sources. Data sets containing sensor outputs were requested from JIP members over a range of multiphase flow conditions. The data sets were to include historical data from downhole monitoring devices, such as pressure/temperature gauges, flow meters, or distributed temperature measurements; wellhead pressure/temperature or other wellhead measurements; seabed measurements, including multiphase flow meters; and topside measurements, including multiphase meters or test or bulk separator measurements. Data could include individual and combined well stream flows. Topside sales or allocation measurements were also welcome.

Unfortunately, despite unrelenting efforts to get this data throughout 2009 and 2010, a data set legally released for use in the project was never obtained. This was not for lack of interest on the part of the JIP members. In fact, this dismayed the JIP task group members who worked hard to gain the release, which was ultimately lost at the corporate level, often due to very restrictive policies regarding release of field data, particularly from deepwater wells.

Early on in the task, it was envisaged that the VFMs would be evaluated against simulated reference data in addition to the field data. When it became clear that no actual field sensor data would be obtained, the evaluation plan continued with only the simulated reference data. The benefit of the simulated data is that any test conditions desired can be applied. The drawback to simulated data is that it lacks the realism of drifting sensors, noise, and other errors that, in fact, constitute the real challenge of virtual flow metering. To avoid this drawback, and to reduce the work time requirement for the VFM suppliers, the reference data was provided as single data sets at a point in time instead of time-based data sets over a period of time. In some cases several data sets were provided over a period of time of several months, but the input data were still “snapshots” in time.

The reference data was created by setting up a reservoir-wellbore-riser model to generate pressure and temperature and flow rate values at points along the flow path. Specific points were selected along the flow path to represent field sensors. There are two points downhole, representing downhole permanent gauges at two different depths, and points just upstream and just downstream of the choke at the seabed wellhead. The model was run to generate flow data over a three year period, a time frame in which the reservoir pressure would drop precipitously to create

multiphase flow conditions in the wellbore. This data set served as the reference data for all three rounds of simulation in the evaluation. The model used to generate the simulated field data set is the transient multiphase flow model, OLGA version 5 (3 phase) with PVTSim. The license was provided to the task subcontractor, MSI, free of charge for the duration of the task by SPT Group.

In early discussions with the VFM suppliers, it was determined that the VFM typically focuses on modeling the flow rate of the well at the wellhead, and does not include riser and topsides modeling. Riser and topsides modeling is usually achieved with a separate model. Therefore, the evaluation in Task 4 was confined to wellbore flow rate modeling using VFMs, and does not include riser and topsides modeling.

Since each VFM software may use a different set or format of input data, the simulation rounds needed various types and formats of information. The simulation input information was provided to VFM vendors in a configuration file. The file contains the following information:

Well Trajectory: Figure 1 gives the trajectory of the well. Horizontal displacement from the reservoir is in x axis and vertical depth from the reservoir is in y axis. This well trajectory is taken from an actual deepwater well, as provided by a JIP member.

Well Completion: A detail description of casing, tubing and downhole instrumentations is given in Table 1 and 2. This well completion is taken from an actual deepwater well, as provided by a JIP member.

Choke Report: The valve coefficient (Cv) as a function of the stem position is given in Table 3.

Fluid Composition: Fluid Compositions are given in Table 4. The EOS model and equations utilized to generate the fluid properties were provided by the PVTSim model. A cost-free license was provided to the task subcontractor, MSI, by CalSep.

Heat Transfer: Thermal conductivity of the materials and geothermal gradient of the formation are given in Tables 5 and 6.

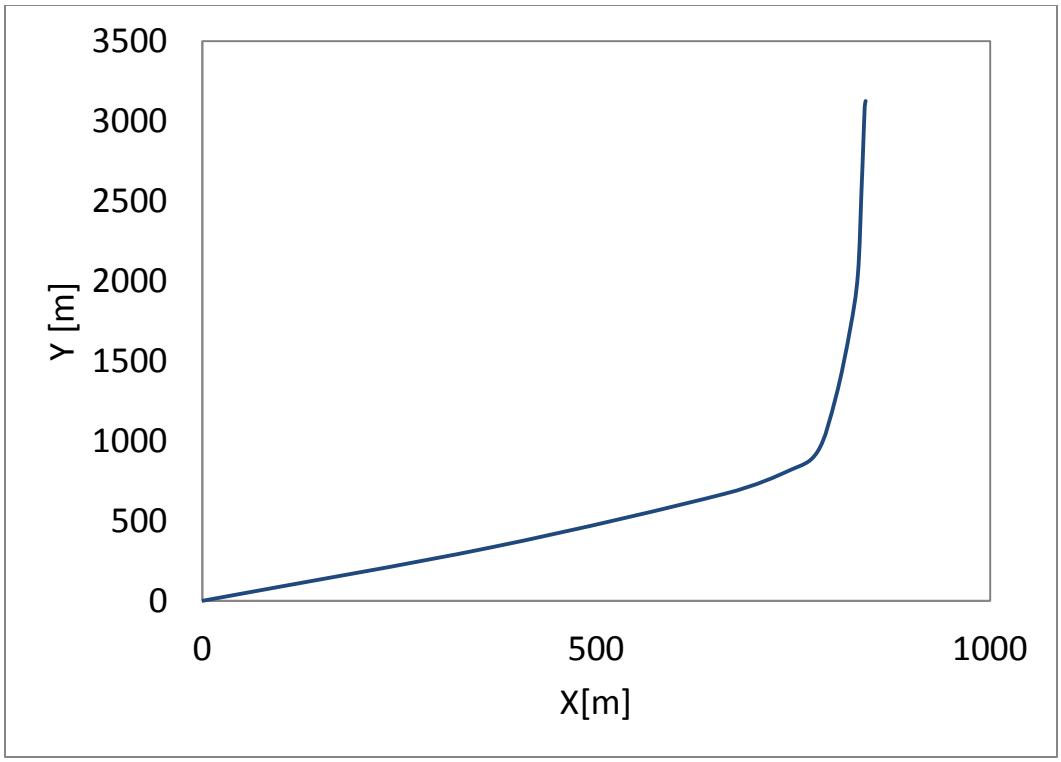


Figure 1: Well Profile

Table 1: Casing Information

Depth from Surface		Casing 1st			Casing 2nd			Casing 3th		
Ini (ft)	End (ft)	Material/ Grade	Internal Diameter (mm)	Wall Thinkness (mm)	Material/ Grade	Internal Diameter (mm)	Wall Thinkness (mm)	Material/ Grade	Internal Diameter (mm)	Wall Thinkness (mm)
0	114	Steel	184.275	11.049	Steel	277.239	12.192	Steel	428.6231	20.6248
114	3554	Steel	218.018	16.249	Steel	371.382	20.192			
3554	7198		218.018	16.49	Steel	371.382	20.192			
7198	9614	Steel	296.275	16.249						
9614	11246	Steel	198.6	19.17						

Table 2: Tubing/Downhole Equipment Information

Depth from Surface	Tubing/Downhole Equipment				
Ini (ft)	End (ft)	Material/ Grade	Internal Diameter (inches)	Wall Thinkness (inches)	Description
0	11246	Steel	4.699	0.414	Tubing 5-1/2 x 23 lb/ft
11246					Production Packer

Table 3: Stem Traveling Position Table

Stem Traveling Position Table		
StemTravel [in]	Cv	%Opening
0.00	1.02	0.09
0.22	3.05	5.37
0.44	11.53	10.95
0.70	30.76	17.43
0.96	51.06	24.00
1.22	65.99	30.34
1.50	94.89	37.33
1.76	114.12	43.98
2.04	141.95	50.90
2.31	165.47	57.68
2.83	205.01	70.72
3.08	218.86	76.83
3.32	230.56	82.79
3.56	245.49	88.98
3.79	253.97	94.71
4.00	254.93	99.93
4.01	256.00	100.00

Table 4: Fluid Composition

Component	Mole Fraction [%]	Component	Mole Fraction [%]
CO2	0.795	C11	2.032
N2	0.149	C12	1.732
C1	41.886	C13	1.722
C2	7.644	C14	1.507
C3	7.507	C15	1.408
I-C4	2.798	C16	1.032
N-C4	3.824	C17	0.832
I-C5	2.099	C18	0.785
N-C5	1.627	C19	0.623
C6	2.689	C20	0.491
MCYC-C5	0.688	C21	0.421
BENZENE	0.195	C22	0.344
CYCL-C6	0.746	C23	0.293
C7	2.387	C24	0.242
MCYCL-C6	1.435	C25	0.221
TOLUENE	0.422	C26	0.177
C8	2.769	C27	0.153
C2-BENZENE	0.073	C28	0.131
M&P-XYLENE	0.345	C29	0.125
O-XYLENE	0.185	C30+	0.637
C9	2.322	MW	71.8
C10	2.508	API Gravity (Single Point Flash)	47

Table 5: Thermal Conductivities of Material

Material	**Thermal Conductivity (W/m-K)**
STEEL	39
CEMENT	0.29
SOIL	1.5

Table 6: Geothermal Gradient of Formation

TVD [ft]	T [°F]
0	39.2
114.0419984	39.2
974.0420259	46
1834.074862	61
3554.120849	81
4674.560517	100
6075.840089	118
7198.418866	136
7617.185283	154
8145.564565	172
9613.806082	190
11246.0896	208

4.3 Specifications and Performance:

The aim of the evaluation is not to compare the results of models under study to the results of the model used as reference. This is not a test to see how well commercial models can match the model used as reference. Instead, the evaluation focuses on the variation in results over a range of conditions. The reference data provides a known case. Generally, the deviation between the results of the model under study and the results of the reference model are used in the evaluation. The evolution of the deviation over the range of conditions is useful to interpret how the models behave.

The deviation is a measure of the difference between reference flow rates to VFM predicted flow rates at standard conditions. This calculation is made when the system is considered statistically stable. Relative deviations are calculated for all rounds with given equation below.

$$Relative\ Deviation\ (\%) = ((X_{VFMprediction} - X_{reference})/X_{reference})*100$$

$X_{VFMprediction}$ is the predicted value by VFM suppliers

$X_{reference}$ is the reference value

Relative deviation graphs are plotted for all VFM results and also similar graphs are plotted for comparisons of all the VFM. These are provided in Appendix C.

4.4 Case and Data Files

For each round, sample data which is representative of the typical operating conditions are provided. Each case file describes the content of data file to the supplier. In this section, information is given for three rounds.

4.4.1 VFM Simulation - Round 1

The aim of Round 1 was to evaluate the performance of VFMs without tuning, "out-of-the-box," so to speak, and to evaluate the prediction versus the quantity and type of input data provided. In Round 1, no tuning data was ever provided to the suppliers. Tuning data is typically a data set of pressures and temperatures and corresponding flow rate as measured in the well. Since no tuning data was provided, only pressure and temperature data was given without any flow rate data.

The format for Round 1 was to run a series of six cases in which each successive case builds upon the previous case. Table 7 below summarizes the six cases of Round 1. All simulations are in steady state conditions, and PVT data are provided for simulations. Each case has 5 sub cases with different choke openings and values. The first case, Case 1, provided an extremely limited amount of information to use to predict the well flow rate: upstream choke P and T, and the downstream choke P only. After providing the results of their flowrate prediction for Case 1, the additional input data for Case 2 was then provided. In Case 2, this was the downstream choke T. The VFM supplier recomputed their flowrates with the additional information, and after submitting the results, could access the input data for Case 3, and so on. Gradually, over the six cases, more data was provided to improve the flow rate prediction. It is noted that the downhole pressures were provided first without temperature, and then the temperatures were provided in order to evaluate the importance of the availability of temperature data.

More sensor physical measurements are provided in every case so that the effect of more data in the prediction would be assessed. Table 7 gives the provided information for each case.

Table 7: Round 1 Case Descriptions

Case	WHUC P [psig]	WHUC T [deg F]	WHDC P [psig]	WHDC T [deg F]	BHP1 [psig]	BHT1 [deg F]	BHP2 [psig]	BHT2 [deg F]
1	*	*	*					
2	*	*	*	*				
3	*	*	*	*	*			
4	*	*	*	*	*		*	
5	*	*	*	*	*	*	*	
6	*	*	*	*	*	*	*	*

Table 8: Requested Predictions

Prediction	Unit	Prediction	Unit
Q_{gsc}	MMscfd	BHP	psia
Q_{osc}	stbpd	THP	°F
Q_{wsc}	stbpd	BHP1	psia
Q_{ouc}	bpd	THP1	°F
Q_{guc}	psia	BHP2	psia
Q_{wuc}	°F	THP2	°F
BHP @4674 ft	psia	WHUC P	psia
BHT @4674 ft	°F	WHUC T	°F

Table 8 gives the requested predictions from each VFM supplier. Relative deviations are calculated for all cases for flow rates at standard conditions.

4.4.2 VFM Simulation - Round 2

The intent of Round 2 is to assess the effect of the quantity and quality of data tuning on the flow rate prediction of VFM software. To do this, sets of training data were disclosed at different time periods (T1, T2, T3 and T4) along eighteen months of production history, as shown in Figure 2. Note that T1 time period is the same as Round 1. Discussion of the seven cases in Round 2 is provided after the description below of the reference data generation.

For every case, VFM software will be tuned-up as instructed and flow rate estimations along the one and a half years of production are carried out. The flow rates are calculated for six specified snapshots in time (A, B, C, D, E and F) throughout the production history.

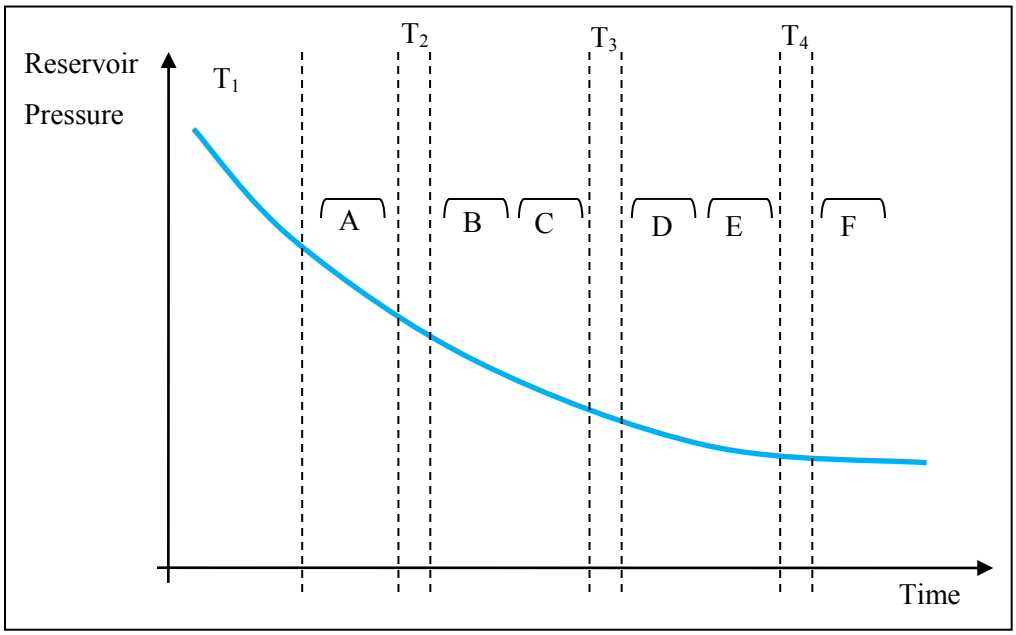


Figure 2. Reservoir Pressure vs. Time

The simulated case consists of one well producing from a reservoir that suffers a strong pressure decline within the time frame. The well and PVT properties remain the same as Round 1. The hydrocarbon composition will not change so further modifications are not needed in the PVT modules.

The reservoir pressure is much higher than the bubble point pressure for at least year 1. At the end of the first year, the reservoir pressure drops close to the bubble point and it reaches the bubble point pressure before the 2nd year.

The well is instrumented with two stations of downhole pressure and temperature gages located at two different vertical depths as defined in the configuration file, and upstream and downstream of the choke pressure and temperature gages.

Accordingly, every group of measurements (A, B, C, D, E and F) includes readings from those eight (8) gauges (WHUCP, WHUCT, WHDCP, WHDCT, BHP1, BHT1, BHP2 and BHT2), while the training set (T1, T2, T3 and T4) includes readings from mentioned gauges plus the flow rate at wellhead and standard conditions.

The pressure depletion is determined as,

$$p_r = p_{wf} + (p_{r,o} - p_{wf})\exp(-bt)$$

In this equation, p_r is the average reservoir pressure at time "t", p_{wf} is the well flowing pressure, $p_{r,o}$ is the initial reservoir pressure, t is time and "b" exponent is related to initial oil in place and the pressure dropdown (Fetkovich, 1996). The exponent "b" is adjusted so that the average reservoir pressure reaches the bubble point pressure at the end of the eighteen months.

The variation of flow rate (q) as function of time is obtained as,

$$q = q_i \exp(-bt)$$

Where, q_i is the initial flow rate produced at specified p_{wf}. The cumulative oil produced (N_p) is obtained by numerical integration or it can be calculated as,

$$N_p = \frac{(q_i - q)}{b}$$

Material balance states,

$$F = N E_0 + W_e B_w$$

Since the reservoir is above the reservoir pressure, the term "F" can be written as,

$$F = N_P B_o + W_p B_w$$

While, the fluid expansion term "E_0" is given as,

$$E_0 = B_o - B_{oi}$$

When water is produced the previous equation becomes (assuming Bw=1),

$$F = NE_0 + W_e$$

Thus, cumulative amount of aquifer water produced (W_p) is obtained as,

$$W_p = N(B_o - B_{oi}) + We - N_P B_o$$

The water production is obtained differentiating W_p with respect to time. Since B_o and N_P are function of the pressure, a numerical differentiation is utilized to obtain the water produced. The size of reservoir is assumed as well as water influx. The volumetric factor is calculated from correlations.

Once the pressure sand rates are predicted, the IPR curves for specific conditions can be determined. Therefore, the dates are randomly chosen from which is obtained the average reservoir pressure and water cut. Notice gas flow rate is not reported because the reservoir is above the bubble pressure. An IPR curve is generated for each of those days as shown in Figure 3.

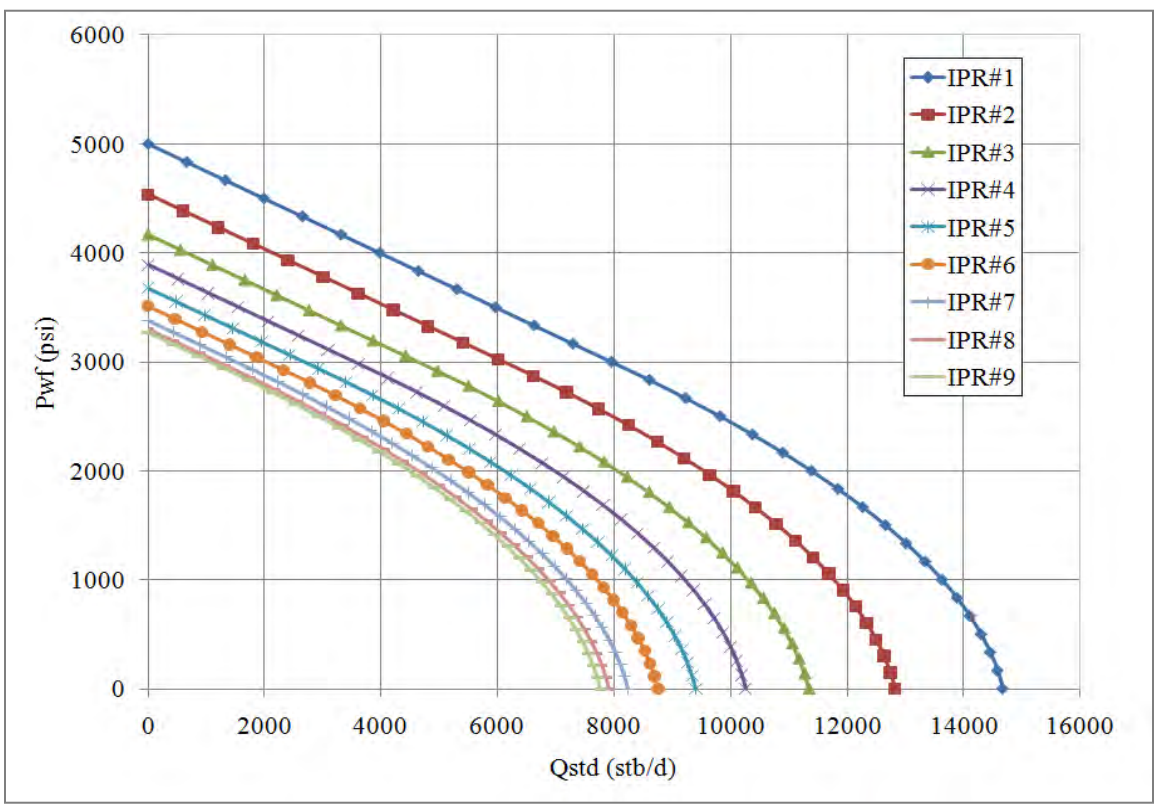


Figure 3. IPR Curves

As in Round 1, Round 2 was set up to be a series of cases in which the initial case provided very limited data, and each successive case provided more data to improve the tuning. Round 2 consists of seven cases. In each case the supplier was requested to output flowrates over the entire time period, represented as times A, B, C, D, E and F, as shown above in Figure 2.

(1) *Case 1*: One flow rate set from "T1" (early time) training set is provided for training and flow rate estimations. The flow rate provided was at high end of the range covered by "T1"
(2) *Case 2*: Three flow rates from "T1" training set are provided (that is, two additional rates to the one already provided in Case 1). The flow rate provided will be cover low, intermediate and high flow rate range of "T1".
(3) *Case 3*: One flow rate within "T3" (late midtime) training set is provided for training. The addition of training data at the late midtime is expected to improve the predictions for the time periods D, E, and F, which follow T3, as well as the preceding time periods.
(4) *Case 4*: The training set in case 3 is complemented with two additional flow rates (3 flow rates in total) at "T3". The training data set now consists of three flow rates at T1 and three flow rates at T3.
(5) *Case 5*: Training data sets (1 flow rate each) were provided for times "T2" (early midtime) and "T4" (late time). This significantly increases the frequency of tuning, though the new data sets are limited.
(6) *Case 6*: Two additional flow rates each for "T2" and "T4" are provided. The flow rate provided will be cover low, intermediate and high flow rate range of "T2" and "T4". The training data set now consists of three flow rates each at T1, T2, T3, and T4.
(7) *Case 7*: Eight training sets (with biased data) are provided. The intent was to see if any VFM supplies detected or corrected the errors in the input data, using the previous six cases as basis for the model.

The flow rate prediction format requested for Round 2 was the same as Round 1.

4.4.3 VFM Simulation - Round 3

Round 3 is intended to assess the relative importance of the different sub-models in the VFM. The evaluation examined five basic models,

1) A1: Choke Model for Pressure Drop
2) A2: Choke Model for Temperature Change
3) B1: Wellbore Pressure Drop Model
4) B2: Wellbore Temperature Model
5) C1: IPR

Minimum set of information related to every model is,

1) A1: WHUCP/WHDCP

2) A2: WHUCT/WHDCT

3) B1: BHP1/BHP2

4) B2: BHT1/BHT2

5) C1 : Pr / J(productivity index)

Different combinations of models are created using A1, B1 and C1 as pivots. Reducing the number of similar sets gives a series of eleven data sets, each with a different combination of data, given in Table 9. Each is in steady state conditions. The VFM supplier is asked to compute well flow rate using each unique data set. Two cases are provided for two different choke openings: 0.18 and 0.4. Each case has the 11 data sets.

Table 9: Round 3 Provided Data for Cases

Set	BHP1 [psia]	BHT1 [deg F]	BHP2 [psia]	BHT2 [deg F]	WHUCP [psia]	WHUCT [deg F]	WHDCP [psia]	WHDCT [deg F]	PR [psia]	AOF [st bpd]
1	*		*		*	*	*	*		
2		*		*	*	*	*	*		
3					*	*	*	*	*	*
4	*	*	*	*	*		*			
5	*		*		*		*		*	*
6		*		*	*		*		*	*
7	*	*	*	*		*		*		
8	*		*	-		*		*	*	*
9	*	*	*	*					*	*
10	*		*			*		*	*	*
11		*		*		*		*	*	*

The data provided in Round 3 uses the same reference model as used in Rounds 1 and 2. Round 3 data occurs later in time than Round 2, in fully multiphase flow conditions in the wellbore.

4.4.4 VFM Product Survey

It proved difficult from the start to do a detailed survey of the VFM products, their approaches, their product features, etc. This is a highly competitive field, and all of the products are proprietary. It was not surprising that the VFM suppliers could not answer our many detailed questions. Similarly, there is not a lot of information available on the products publicly, such as on websites, in brochures or published papers.

To get some information about how the VFM products work an interview was held with technical and sales representatives from each of the VFM supplier companies. From these interviews a list of typical features and characteristics of Virtual Flow Meter software products was constructed. This list generally represents the group products, if not most of the products individually.

In addition, an online survey was conducted with seven of the VFM suppliers participating. The questions again focus on product features and characteristics, but the survey format lends itself more easily to quantifying the results.

Although there are differences between the VFM products, the combination of the interviews and the survey provides the basics of what to expect from a VFM for the non-specialist in multiphase flow modeling. Because the objective of the task was to evaluate VFM products as a group, and not individually, no attempt was made to do a product-to-product comparison of features and benefits. The results of the survey are presented in Appendix D.

5. Results and Deliverables

5.1 VFM Simulations

Participation from the VFM suppliers in the 3 rounds of simulation began with great interest from all, but waned over the course of the task. Seven of the original eight suppliers completed Round 1, while two suppliers completed Round 2 and only one supplier completed Round 3. The reason for drop in participation is primarily one of commercial expediency. The suppliers were not compensated for their time involved in the task, so the work had to be done when time permitted. The economic slowdown and industry layoffs exacerbated the situation in 2010. In some cases the person doing the simulation work left the company, and no one was available to take over. In other cases, with staffing reduced, workload was increased for those employed, and time available for uncompensated work such as this task was very limited or nil. There may also have been a reduction in interest in the task by the suppliers once it was determined that no field sensor data would be made available. From early discussions it was clear that the field data was of great interest for the suppliers to test their models.

The Round 1, 2 and 3 results are presented in Appendix C.

Round 1 was primarily intended to see how the flowrate predictions would improve as additional data, downhole and at the choke, was provided as input to the VFM model. In discussions with VFM suppliers, all agreed that the more data available the better the results would be. However, this did not bear out clearly in Round 1 tests. Generally there was little improvement in the predictions with the addition of more input data. The exception was one company's results which changed dramatically with the addition of the first downhole data, Case 3. This implies the choke model alone was not as good as coupling the borehole model and the choke model. Two other companies' results showed very slight changes as the additional data was provided. A fourth company showed little change until the very last case, with all pressures and temperatures provided at multiple depths downhole and at the choke.

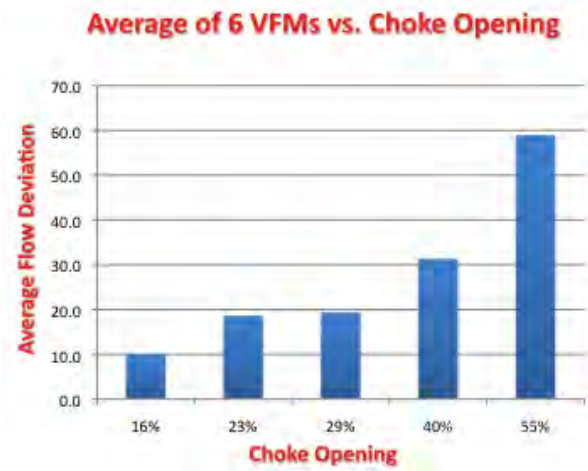
The deviation value, which is the percentage difference between the VFM predicted flow rate and the reference flow rate, for each of the models in Round 1 can be exceedingly high. Some models had deviation in the hundreds of percent, and most were in the tens of percent range. It is noted, however, that these simulations were made without any tuning, aka training. This served as a basis

for comparison with the results in Round 2, in which tuning was performed on the model. Indeed, as Round 2 results show, the untuned predictions were significantly different than the tuned predictions.

The conclusion drawn from the results are that the ability to predict a flow rate with very limited amount of data was reasonably good. Additional data, which was consistent, did not markedly change the prediction, with the possible exception of the choke model in isolation without any downhole data. This is a positive finding as it shows that the flow models are robust enough and sufficiently valid that they can "lock on" to a flow rate rather easily, and the additional information, if consistent, does not change the prediction. The additional data, therefore, is useful primarily as a means to verify the consistency of the input data, to improve the uncertainty of the prediction, or to improve the prediction in the case of biased or erroneous input data.

Analyzing the data turned up two other conclusions. These are demonstrated by the two graphs below in Figures 4a and 4b. Firstly, the VFMs consistently increased the over-diction or under-prediction as the choke increased (the flow rate increased). This is understandable as the differential pressure decreases with the increase in choke size and flowrate, which increases the uncertainty of the flow rate through the choke. The data also shows that the bias in the model, as compared to the reference data, was generally persistent. That is to say that each model predicted rates usually less than or more than the reference model, and remained so over the six cases. A second conclusion is made by looking at the deviations of all the models for case 5, in which downhole pressure data was provided at two depths in addition to choke data. Four of the six models were fairly consistent, while two models were significantly different. Very simple, there are differences in these models or how they are used, and it shouldn't be assumed that one is like another.

It is important to keep in mind, however, that this is not an evaluation of the "accuracy" of the VFMs. Deviations in the range of 10% to 20%, using an untuned model, does not mean the results are in error. They do, in fact, differ from the reference set. It is reiterated that the reference data sets were tweaked so that the pressure and temperature values provided as "sensor data" were not precisely the outputs of the reference model. A range of variation was permitted up to about 2.5% for each value, generated randomly, so as to avoid any VFM getting a perfect match with the reference model.



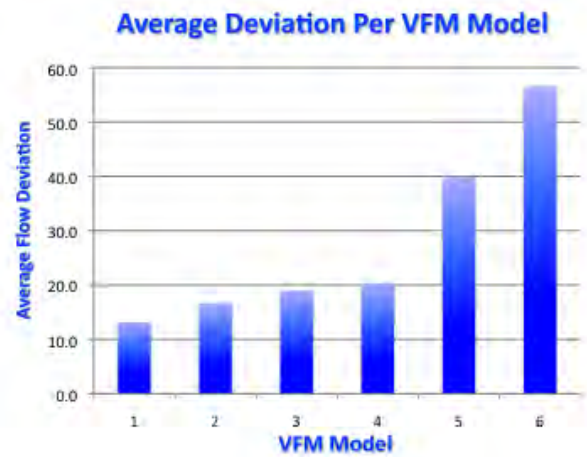


Figure 4a. Average flow rate deviation versus choke opening
Figure 4b. Average flow rate deviation per VFM model

Round 2, being the tuned or trained simulations, intended to demonstrate an improvement over the untuned or untrained results, and to evaluate the quality or quantity of tuning. In discussions with the VFM suppliers, all agreed that tuning was necessary, and that a model couldn't be expected to remain valid forever after the initial tuning, even if the software featured auto-tuning. However, the question of interest was how often is tuning required and what constitutes a good tuning?

To evaluate this a series of tuning data sets were provided at four times over a 3 year production period in which the models were predicting flow rates. Tuning data was provided at the start, then in the middle, then at four different times. Tuning data sets were either provided with only one flowrate-pressure data set or with three data sets representing a broad range of flow rates.

It was anticipated that the single flow-pressure/temperature data set would be less useful as a tuning data set than having three sets over a wider flow range. It was also anticipated that the additional tuning data at later times should improve the later time predictions. What was not known was if there might be a point of diminishing returns, where additional tuning data sets did not improve further the predictions.

One of the VFM models showed a significant change in prediction rates from Case 1 to Case 2, which is the difference between tuning with only one flow rate or tuning with three flow rates over a wide range. The other VFM model did not exhibit the same. It may be, as expected and as exhibited by one VFM model, that tuning the VFM model with multiple flow rates, such as in a multi-rate well test, is preferable to tuning with a single rate well test. The data in this study is insufficient to be

more firm in a conclusion. On the other hand, the ability to tune the model with only one flow rate is encouraging, as in Round 1, where it may suggest that the VFM models are robust and the additional data serve to improve uncertainty or to improve predictions in the case of erroneous sensor data or erroneous tuning data.

Both VFM simulations showed that the addition of tuning data at a later time remarkably improved the prediction. This was most probably due to the evolution of multiphase flow in the wellbore as the pressure dropped below bubble point. It can be noted that the IPR of the reservoir was not held constant over the simulation period. Changing the IPR (the values of which were not revealed to the suppliers) made it difficult to use the reservoir model only to estimate flow rates. However, once the retuning of the model was accomplished with the tuning data set at the midtime, T3, additional tuning data sets at earlier and later times did not obviously change the predictions. It could be argued that the predictions "improved" a little, at least changed, but it is not striking in these results.

Although in this task the first retuning occurred after roughly one year, it cannot be concluded that more frequent than annual tuning is not useful. The retuning requirement depends on the stability of the flowing conditions, as well as the confidence in the model. As an extension from what is observed in the results, it is recommended that more than annual tuning be made at least initially, and then based on the confidence level in the results and any anticipated changes in the production conditions, retuning frequency or timing can be adjusted to less or more frequent as required. In earlier discussions with VFM suppliers, there was a consensus that retuning frequencies of more than annual were generally not practiced and not recommended.

Originally, one of the objectives of the evaluation, as directed by task group, was to try to assess the ability of the VFM to correctly predict flowrates in the event of erroneous input data. In practice within this evaluation task this became a challenge because it was believed that having a round of simulation in which the data was in error would only cause the VFM suppliers to pay close attention to finding and correcting the errors. Of course, errors in sensor data in the real world do not announce themselves. Errors in the input data are not known in advance. So, although the ability to detect and correct bad sensor input data in the VFM modeling process is important to getting reliable flow rate predictions, it is difficult to assess that in a simulation scenario. What was done was to add one additional case to Round 2 in which the input data was biased or in error. With the prior six cases to serve as the database for which the model was built, case 7 served as a small test

to see if errors in the input data might throw off the VFM. Admittedly, this is not clearly a test only of the VFM's auto ability to identify and correct for erroneous input data. There is a human element at play also. Nevertheless, case 7 with biased input data did nothing to change the prediction of the two VFM models in Round 2.

Round 3 simulations attempted to highlight the relative importance of each sub-model in the VFM software. This round was aimed at addressing the question of the reproducibility of the model: If the same flowing conditions persisted, did the model predict the same flowrate, or is it less determinant? Again, this is difficult to do with simulated data. With the same inputs and the same model, there is no reason for the outputs to change. To assess the question of reliability of the model, the question was put another way. Round 3 aimed to identify which inputs had the biggest role in determining the flow rate? Knowing this, confidence in the VFM predictions could be maintained by optimizing the important input data.

The VFM simulation in Round 3 did not show clearly a data set combination that was especially potent or impotent in its ability to predict flow rates. At first glance case 6 result is anomalous, but it is not clear why. Looking at the data from the smaller choke size, the cases 4, 5, 6, and 11 are different, but there is not a common factor among them that explains that, either. Perhaps more could be said if more of the VFM suppliers completed the round.

In summary the following conclusions were drawn from the results for the untrained and trained VFM model predictions.

Untrained VFM model predictions (Round 1):

1. Persistent bias for most models, + or –
2. Over/Under-prediction increased with flow rate (inverse with pressure drop)
3. Generally no improvement by adding more P, T data
4. No obvious benefit of temperature data versus pressure data

Trained VFM model predictions (Round 2):

5. Any training is better than no training
6. Multi-rate training data improves prediction
7. Re-training improves prediction
8. Did not evaluate practical limit to training frequency

9. Routine training (comparison against sensor Q, P, T data) provides best confidence

5.2 VFM Product Survey

Interviews were held with technical and sales representatives from each of the VFM supplier companies. All but one of the interviews was held face-to-face; one was done over the phone/internet. It was not possible to get a comprehensive description of the VFM products and features from the interviews (nor available published information), but the following is a list of the typical features and characteristics of Virtual Flow Meter software products. This list generally represents all of the products, although there may be some variances with each product. This is not to imply they are all almost the same; because they are not. Hopefully, however, this provides at least a basic list of what to expect from a VFM.

- Calculates oil, gas and water production rates, watercut, gas oil ratio, distribution of pressure, temperature, velocity, etc.
- Utilizes input from pressure and temperature transmitters, density meters, watercut meters or flow meters
- Predicts outputs from reservoir to processing facilities (may be in conjunction with additional software module)
- Useful for validation of well test, reconciliation of flow meters, replacement of flow meters
- Useful for identifying sand erosion and sand lift velocities and water lift velocity
- Useful (with other products) for tracking liquid slugs, MEG, pigs, identification of hydrates, control of chokes, monitoring for erosion, corrosion, wax or leaks
- Typically used to look ahead and perform “what if” scenarios
- Uses field data from control system – OPC or SQL format usually
- Has filters and algorithms to check data validity, instrument failure detection
- Outputs flow rate at high frequency per well, combined flowline or at separator inlet; may output data at lower frequency, such as hourly
- Boundary conditions usually defined PI or BHP at inlet (bottom of well)
- Uses subcomponent models such as choke delta P for various flow line features
- Typically tune/train model with downhole and surface pressure values
- Tuning system is typically automatic, but can be manually tuned; some only manually tuned
- Have some ability to detect bad sensor data, raise alarms and correct or ignore bad data
- May utilize uncertainties associated with sensor input data

- May output flowrate uncertainties
- Operate in steady state mode; some also have transient flow model engines
- PVT data computed continuously; some can use preset data tables
- Model selection, where multiple models are used, may be automatic or manual
- Use mechanistic two phase flow models, flow regime based
- Use neural network in conjunction with hydrodynamic and thermodynamic models
- Typically initially train model on 3 months to 6 months of data, even better over first year.

An online survey was conducted with seven of the VFM suppliers participating. The responses to the survey were given by the VFM suppliers themselves. A summary of the results of the survey are described below. The complete results are in Appendix D.

- Detailed knowledge of (at least some) flow modeling is required to set up the VFM: 86% (of responders); one responder says no detailed modeling knowledge needed at all
- Set up of the VFM is typically provided by the VFM supplier with the operator
- Utilizes some artificial intelligence: (71%)
- At least some auto-tuning (86%); mostly uses auto-tuning (29%); not at all (14%)
- Uses Steady state modeling (71%)
- Uses Pseudo-steady state modeling (29%)
- Uses Transient modeling (43%)
- Data is acquired directly from SCADA (100%); or from historian database (71%)
- Quality check is performed most of the time on sensor data prior to modeling (86%)
- Oil flow rate is determined without watercut provided as input data (86%)
- Flow pattern recognition is utilized in model (71%)
- Definitely covers the full range of 3 phase flows (86%)
- Responds mostly or definitely to slug flow with slug length on order of minutes (71%)
- Responds somewhat or not at all to slugs with length on order of seconds (71%)
- Primarily utilizes rigorous multiphase flow physics to determine the flow and pressure drop (86%)
- Primarily uses numerical processing (not rigorously tied to flow physics) to predict the flow and pressure drop/pressure of system: (14%)
- Utilizes a combination of rigorous multiphase flow physics and numerical modeling to determine the flow and pressure drop: definitely (100%)

- Is intended mostly to be used out-of-the-box without training to flow and pressure data (14%)
- Mostly does not require flow rates as sensor input (such as from multiphase flow meter) (72%); not at all (17%) – meaning definitely does require flow rate as input
- Definitely makes use of input variable uncertainties (86%)
- Computes uncertainties with outputs mostly (71%)
- Identifies emulsion, scale, wax, asphaltenes, hydrates only somewhat or not at all (71%)
- Applies to installations with gas lift (100%)
- Makes use of IPR reservoir data (100%)
- Is well-suited to black oil and dry gas (100%)
- Is well-suited to condensates, volatile oils, heavy and extra-heavy oils (86%)

Over the course of the interviews and the project, it was possible to ascertain some of the wishes of the VFM suppliers, what they view as important to improving the quality of VFM products for the future. These are:

- Gain recognition with regulators
- Add ability to handle multiple zones downhole
- Improve choke position indication or flow area determination at choke
- Access to real data sets to validate flow models
- Identify the software operational settings of most value to operators
- Consolidation of PVT and thermodynamic models used in various modeling
- Reducing or eliminating sensor drift
- Get feedback from software users

6. Conclusions and Areas for Continued R&D Investigation

This task set out to examine flow models to make the industry's first independent, public-domain evaluation of their use as virtual flow meters (VFMs). The task aimed to address basic questions about VFM performance, about the state of the technology as a whole, rather than the performance of individual products. The following are our findings.

Although commercial VFMs essentially derive from multiphase flow in pipe models of flow/pressure/temperature, there are plenty of unique approaches to the commercial offerings for virtual metering. There are VFMs with steady state flow models and those with transient flow models. There are VFMs with proprietary models and auto selection of models for user friendliness, and there are VFMs with published models and user selection for a more user-driven process. There are VFMS that emphasize hydrodynamics, or thermodynamics, or neural networking in resolving flow rates. There are models with built-in PVT models, or without. It was also learned that there is very little published information about the commercial VFM products, and that suppliers were somewhat reticent to reveal all of the features of their software in the context of this evaluation. Certainly it is understandable that product differentiation is a key part of the competitive market.

For most of the commercial products, the VFM could be thought of as a wrapper around a multiphase flow in pipe model. Though the flow in pipe model is an essential engine, it is the wrapper that makes the flow model a VFM. In a simplest case, all of the VFMs tested were able to compute flowrates given a set of pressures and temperatures in a known wellbore. The range of results was about a 30% span without any training performed with known flow rates. After training, the range of results was over a much smaller span. It was examined what happens when more P, T data was progressively provided, but found there was little change in the predictions. For the most part, a difference in predictions with or without downhole temperatures was not observed. This reinforced the notion that the VFM models are fairly effective at determining the flow rate, even from limited input data sets. So it seems that determining the flow rate from wellbore pressure and temperature sensor data is something that is basically achievable.

Additionally, it was found that the VFMs consistently increased the over-prediction or under-prediction as the choke size increased (the flow rate increased). This is interpreted to be due to differential pressure decreases associated with the increase in choke size and flowrate. The drop in

differential pressure increases the uncertainty of the flow rate through the choke. The data also shows that the bias in the model, as compared to the reference data, was generally persistent. That is to say that each model predicted rates usually less than or more than the reference model, and remained so over the six cases. Furthermore, comparing the deviations of each the models, it was observed that four of the six models were fairly consistent, while two models were significantly different. The conclusion drawn from this is that there are important differences in these models and how they are used, and it shouldn't be assumed that one is like another.

The test of VFMs with training of the models provided several results of interest. Firstly, it seemed that across the board training improved the consistency of the results. Furthermore, it seemed that training over a wide range of flows is preferable to a narrow training range. This may show that modeling outside the training range increases the risk of bias or error in the flow rate estimations. Although the VFM ability to identify bad input data was not evaluated, the fact that the trained results were consistent lends confidence that errant input data would be easier to detect and identify. It was also tried to evaluate how VFMs responded to updates in training data. Only one scenario was tested, but the test did show that the additional training data at a later time benefitted flowrate prediction. It is difficult to address the question of how often a VFM needs to be re-trained. It depends on conditions, the VFM, the training done initially, etc.

The hydrocarbon fluid PVT properties and phase behavior models were not tested, as that is a separate and specific challenge and one which is not unique to wellbore modeling. It was also difficult to test the ability of the VFM to decipher good sensor input data from bad since simulated sensor data were used. Simulated data, even with some randomness applied to the result is an inadequate substitute for real sensor data when testing the VFM ability to detect sensor problems or errant input data.

The tests of VFM in this task could not assess the bias or uncertainty of the results. The bias determination requires good quality flow measurement, which was not available. The uncertainty requires an evaluation of time-based data, or a more extensive evaluation, and should probably be done with real field measurements instead of model outputs. What the evaluation did show was that the spread in results, or the disagreement in results amongst VFMs, without model training was broad, particularly for larger choke sizes or larger flow rates. The VFMs tested after training showed a far more consistent response.

To further the effort of this task it is recommended to run a comparison of several VFM models to installed flow meters using near real time wellbore data over approximately one year of time. The real well data will enable the evaluation of those aspects of modeling described above that cannot be achieved with simulated sensor data. It is recommended to hold PVT properties and phase behavior separate from the rest of the model in order help evaluate the hydrodynamic and thermodynamic modeling capability. VFMs using transient models should be treated separately from those using steady state models. If possible, access to the VFM model should be controlled such that the models could be tested for a period of time without retraining or updating to try to evaluate the effectiveness of auto-tuning functionality. It may be possible to run two models simultaneously; one being retrained and one held unchanged.

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Acknowledgements

There can be no doubt that programs such as the DeepStar 8302 and the RPSEA 07121-1301 have done much to improve our understanding and capabilities. By bringing the deepwater operators together to address these seriously important problems, not only have key technical issues been tackled, but this has happened with the cooperation among these major operating companies, many of which must work together as partners in the large deepwater applications in the Gulf of Mexico and beyond. By doing this work together, it is far more likely that the directions chosen will be accepted by the deepwater community at large.

Support is acknowledged as provided by the US Department of Energy for the RPSEA Initiative, which has provided the impetus and support for the work presented here. The members of the 07121-1301 Joint Industry Project are also duly acknowledged as having provided not only financial support for the project, but also contributed the expertise of their brightest and best subsea and measurement engineers. These are: BP, BHP, Chevron, ConocoPhillips, Shell, Statoil, and Total.

Many contributions were made by the lead contractor, Multiphase Systems Integration, LLC. The effort put in by the VFM vendors who carried out the simulations is also acknowledged. These are: ABB, Belsim, FMC, Kongsberg, MSI-Kenny, Schlumberger, SPT. Generous donations were made by SPT for the of the OLGA license and training, and Calsep for the PVTSim license. Both licenses were provided free of charge to the task throughout the project, which enabled the generation of the simulated data sets.

The leadership from Thomas Danielson of ConocoPhillips and Carlos Avila from Chevron, is particularly noted, as well the early set up of the project provided by Dean Wade, formerly of BHP-Billiton. The individual contributions of Eduardo Pereyra and Jose Gamboa of MSI, and the support of MSI's management were much appreciated.

Appendix A: Financial Results

Total Budget Amount:	$446,913
Total Amount Spent:	$340,725
Subcontractor Simulations and Reference Data:	$183,761
Direct Labor:	$139,541
Travel:	$6,242
Consultants:	
General & Administrative:	$11,181
Amount Under Budget (Over Budget):	$ 106,188
RPSEA Total Amount Spent:	$272,580
Cost Share Total Amount Spent:	$68,145

Appendix B: Nomenclature

AOF:	Absolute Open Flow, stbpd
BHP:	Bottom Hole Pressure near perforation, psi
BHT:	Bottom Hole Temperature near perforation, °F
BHP@:	Bottom Hole Pressure at given measured depth, psi
BHT@:	Bottom Hole Temperature at given measured depth
BHP1:	Bottom Hole Pressure Station 1, psi
BHT1:	Bottom Hole Temperature Station 1, psi
BHP2 :	Bottom Hole Pressure Station 2, psi
BHT2:	Bottom Hole Temperature Station 2, psi
PI:	Productivity Index, bbl/psi
Qouc:	Actual (local) oil flow rate upstream choke actual conditions
Qguc:	Actual (local) gas flow rate upstream choke actual conditions
Qwuc:	Actual (local) water flow rate upstream choke actual conditions
Qosc :	Oil flow rate at standard conditions, stpd
Qwsc :	Water flow rate at standard conditions, stbpd
Qgsc:	Gas flow rate at standard conditions, MMscfd
WHP:	Wellhead Pressure, psi
WHT:	Wellhead Temperature°F

WHUC P: Upstream Choke Pressure, psi

WHUC T: Upstream Choke temperature°F

WHDC P: Downstream Choke Pressure, psi

WHDC T: Downstream Choke Temperature°F

Appendix C: Simulation Results

Round 1 Results

Figure 4 through 27 are graphs for each company to compare the evolution of flow prediction with additional data and effect of choke openings. Almost for all cases, increasing choke opening increases the relative deviation percentage for choke openings. However, adding more data does not create significant change in predictions.

From Figure 28, graphs are plotted to compare all companies' results for different cases. Figures 28 through 30 are comparisons for Case 1 gas, oil and water predictions. Figures 31 through 33 are comparisons for Case 5 which has 6 gauges.

Also, for each choke openings, from Figure 34 to 38 are plots for relative deviation versus number of gages. In these graphs, effect of number of gages on oil prediction is shown for each choke openings.

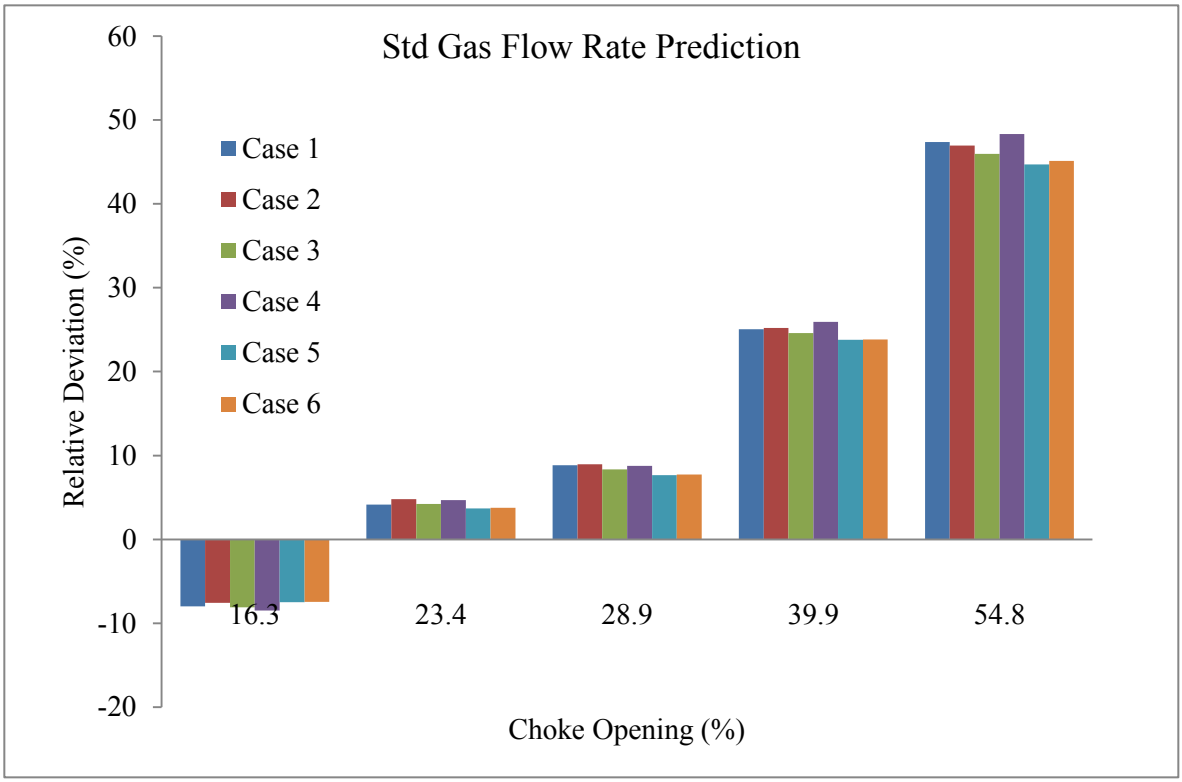

Figure 4. Gas Flow Rate Prediction, Company A

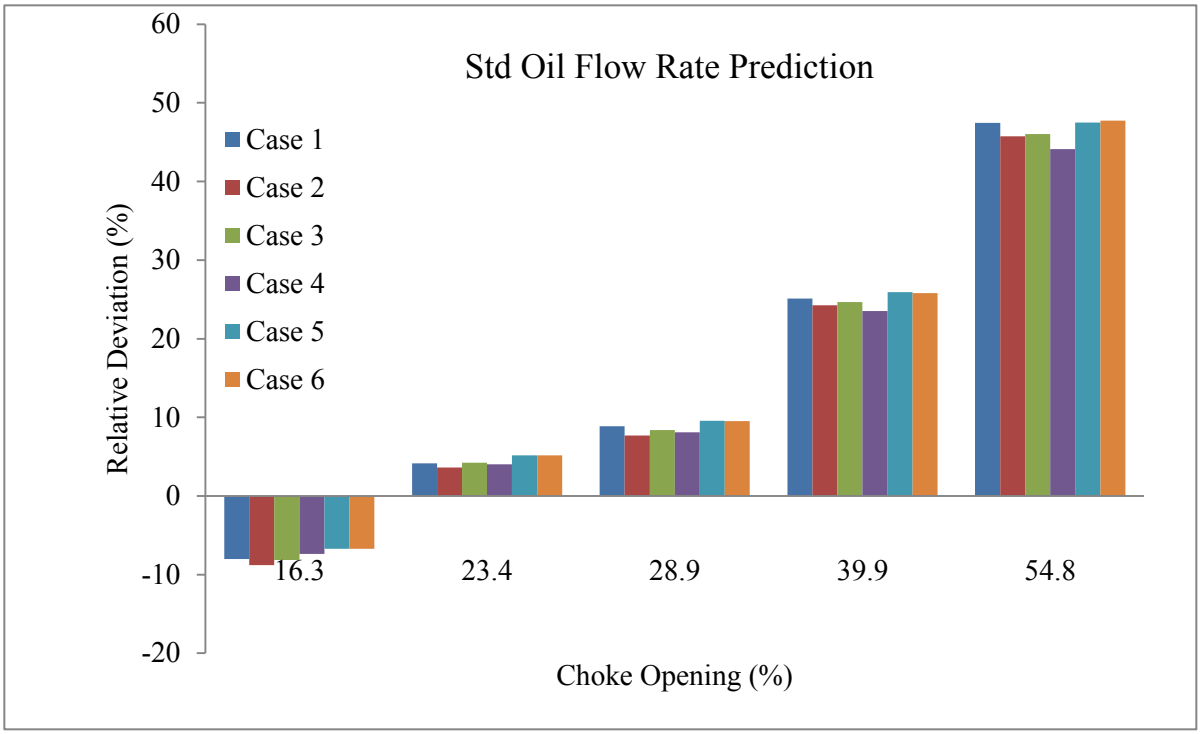

Figure 5. Oil Flow Rate Prediction, Company A

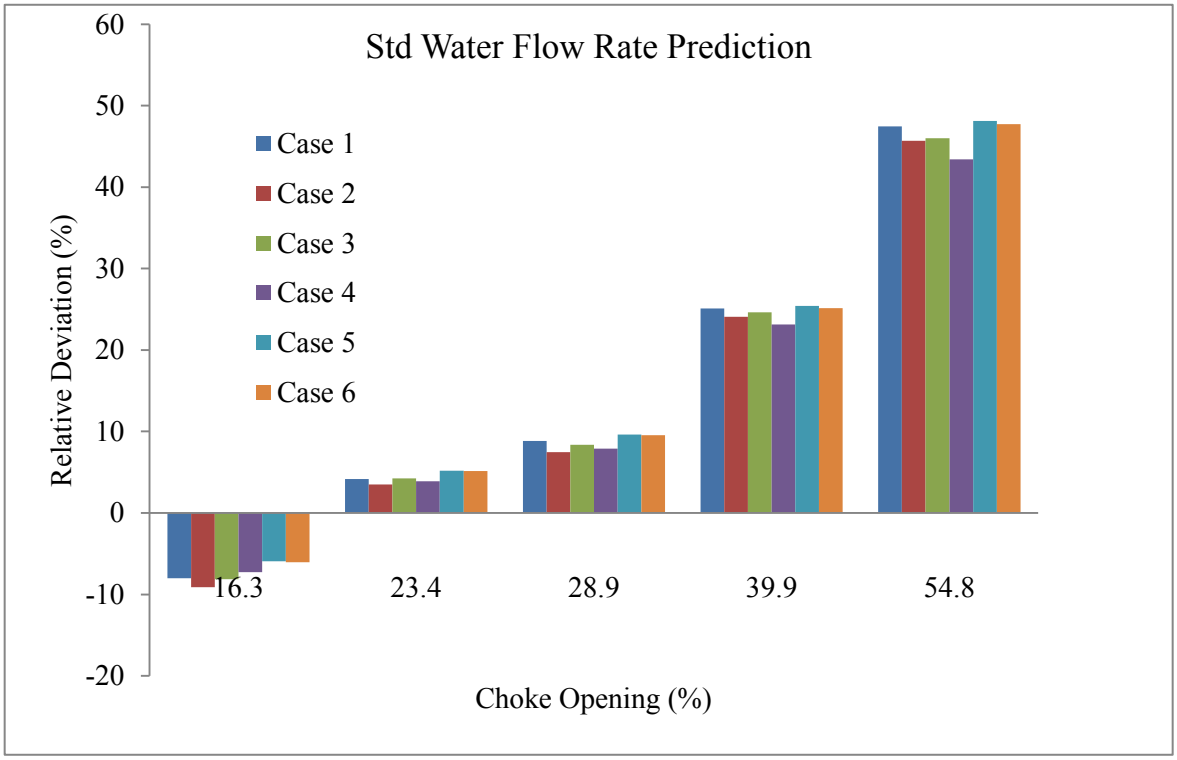

Figure 6. Water Flow Rate Prediction, Company A

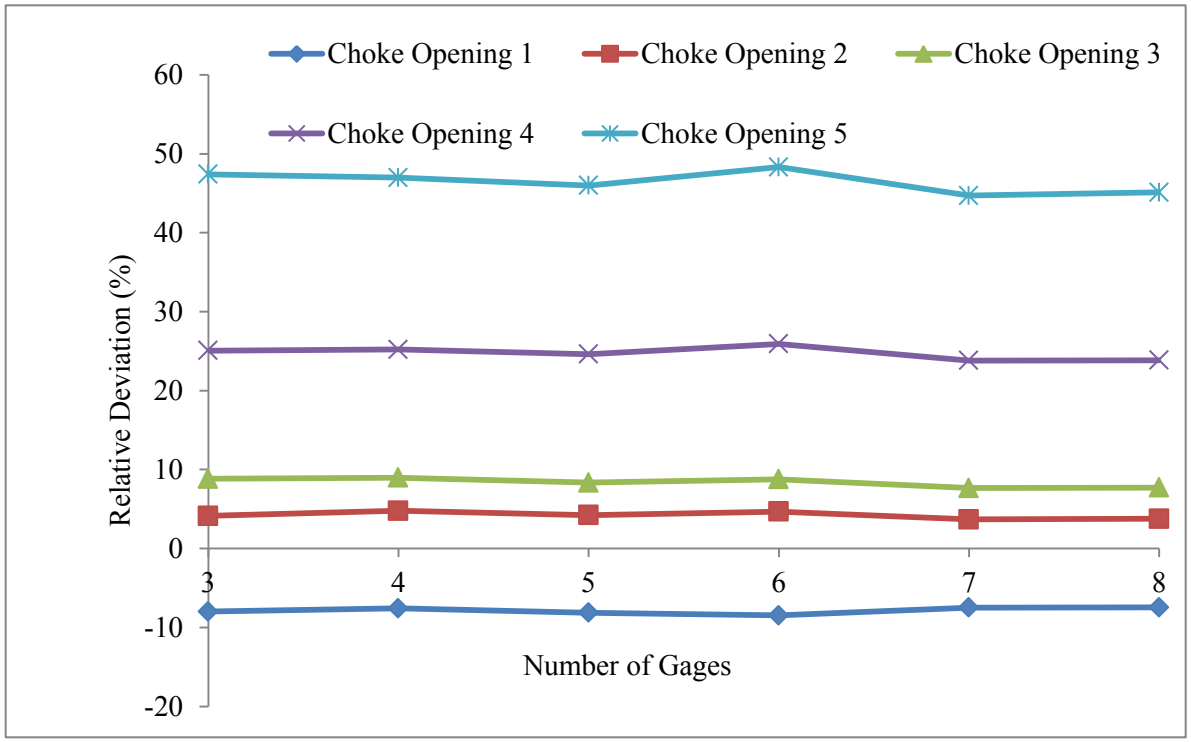

Figure 7. Relative Deviation vs. Number of Gages for Gas Prediction, Company A

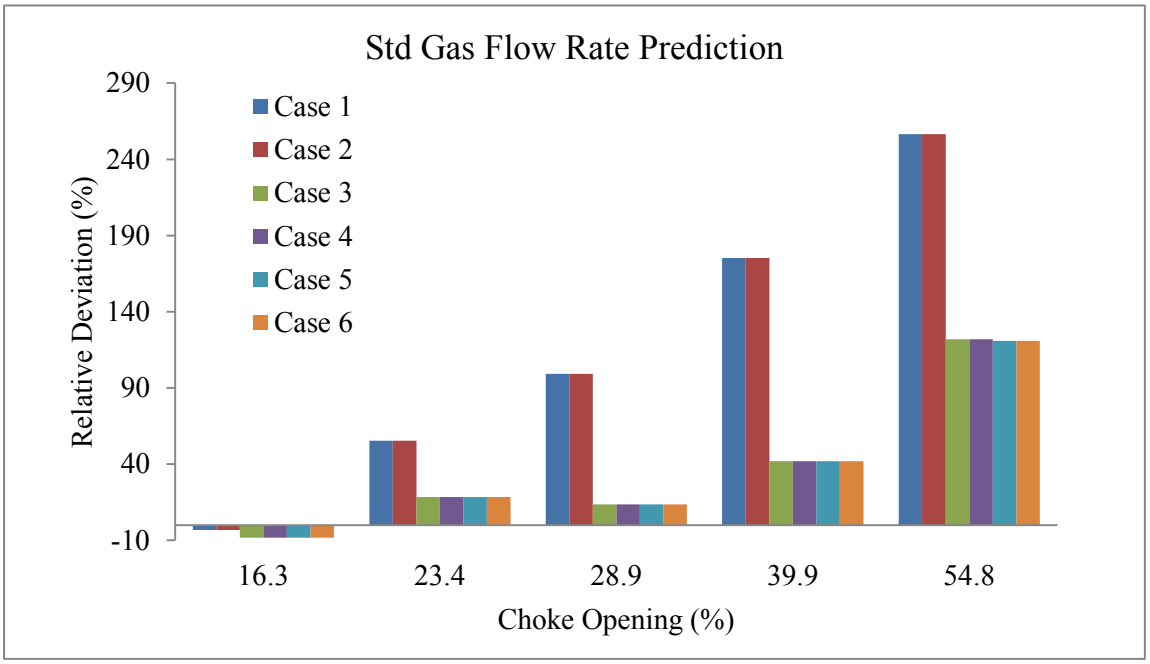

Figure 8. Gas Flow Rate Prediction, Company B

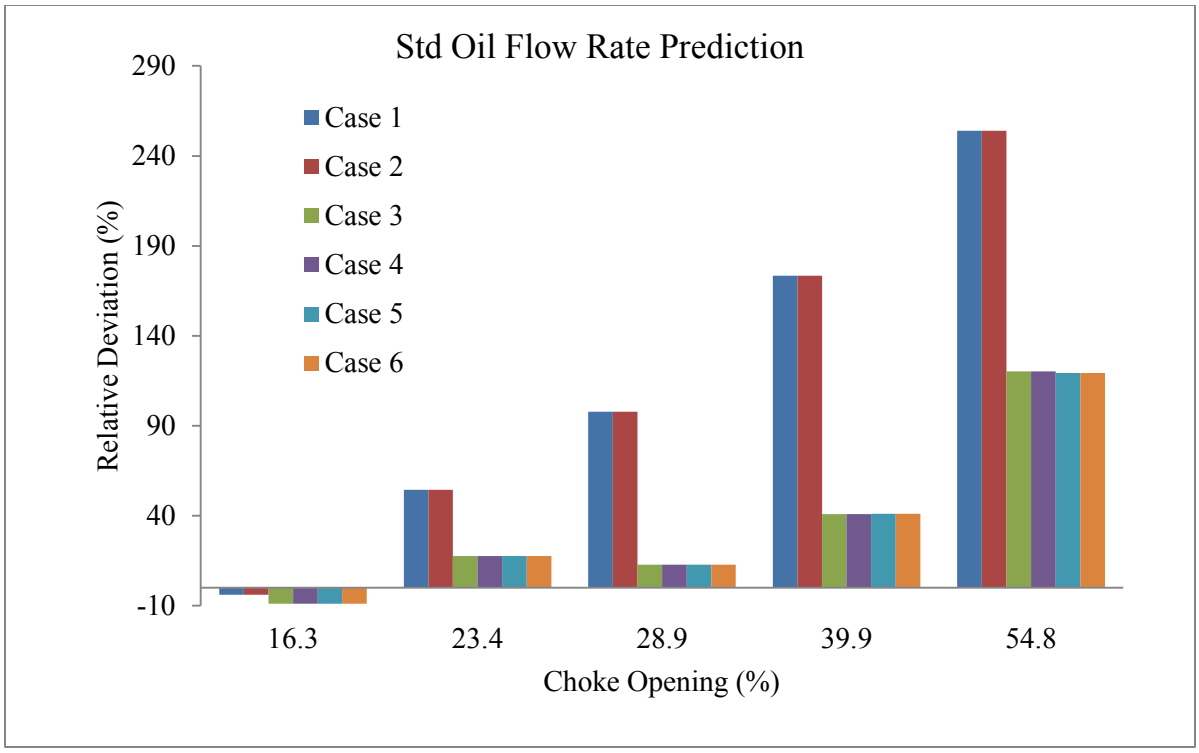

Figure 9. Oil Flow Rate Prediction, Company B

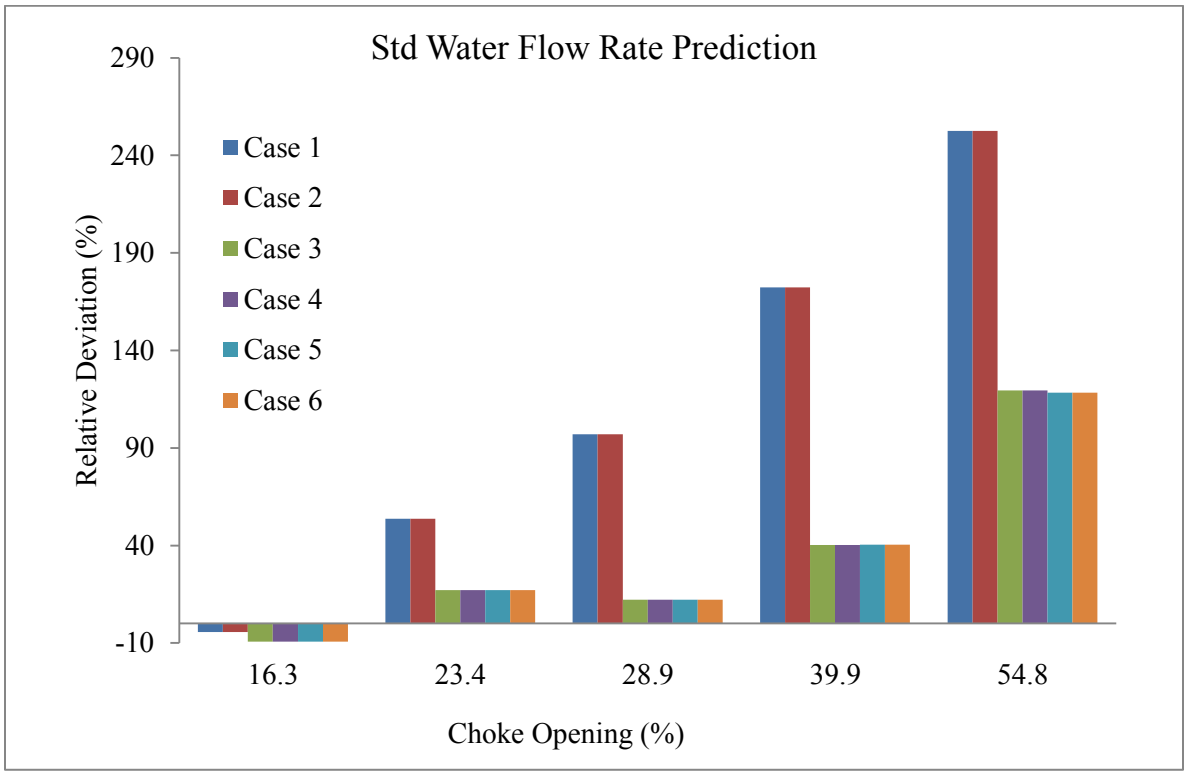

Figure 10. Water Flow Rate Prediction, Company B

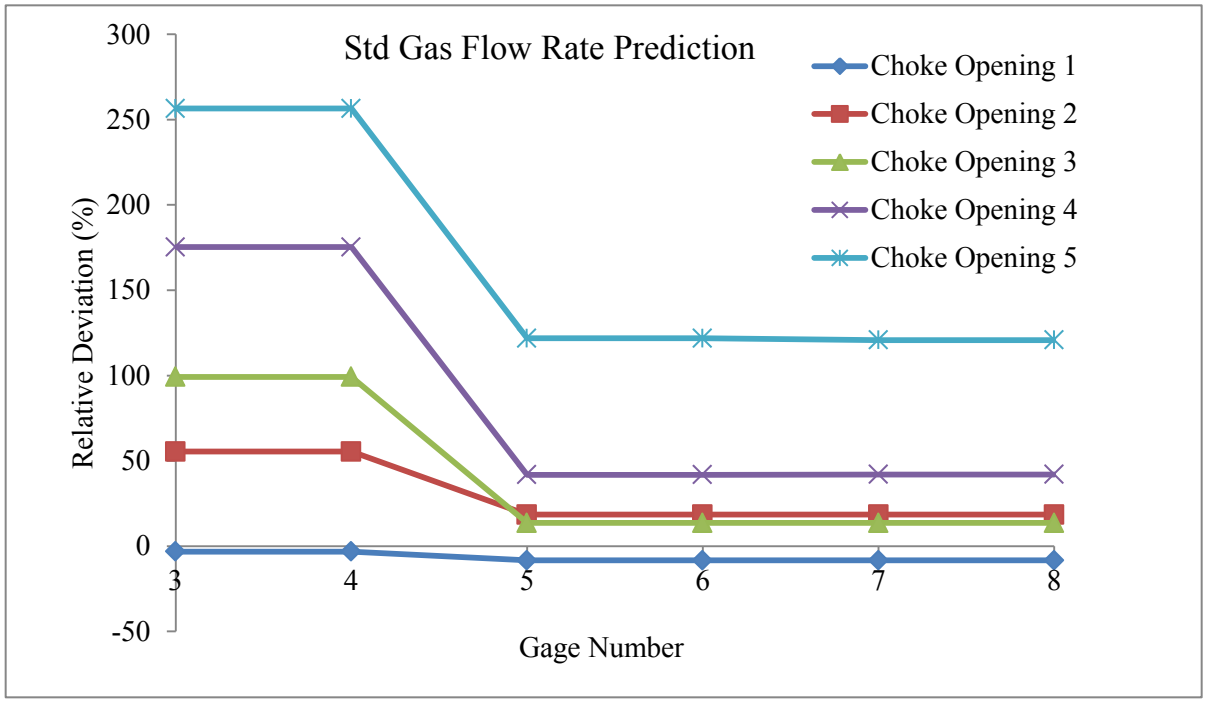

Figure 11. Relative Deviation vs. Number of Gages for Gas Prediction, Company B

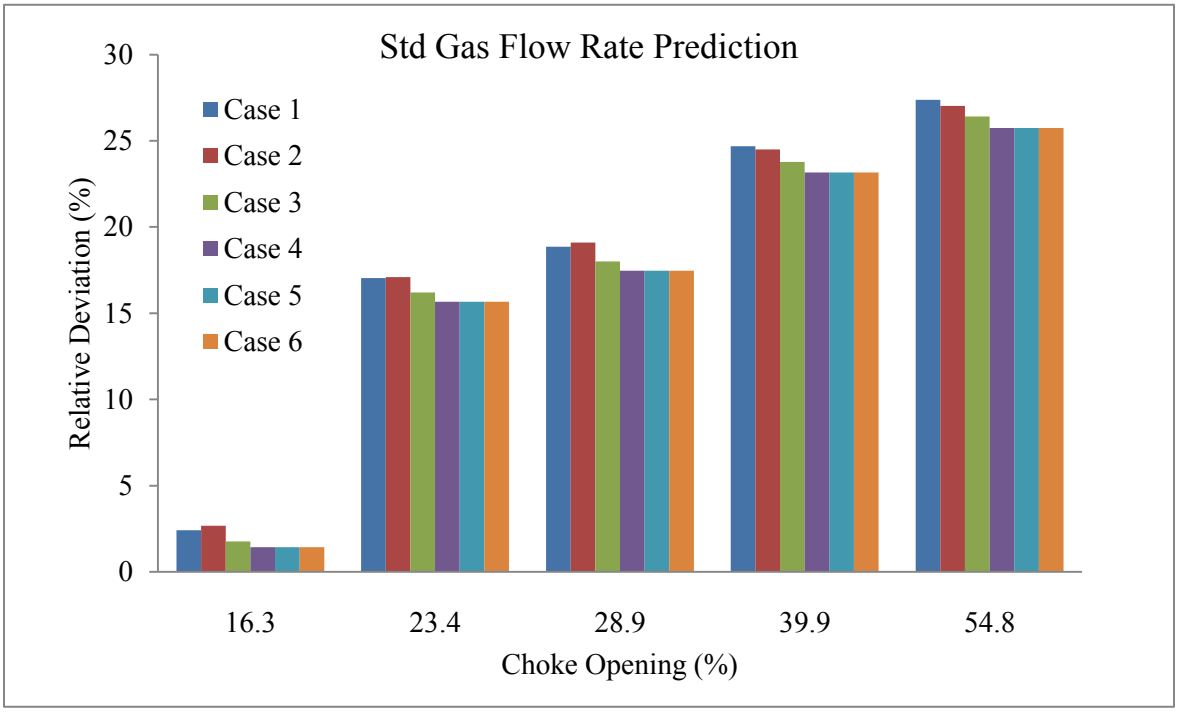

Figure 12. Gas Flow Rate Prediction, Company C

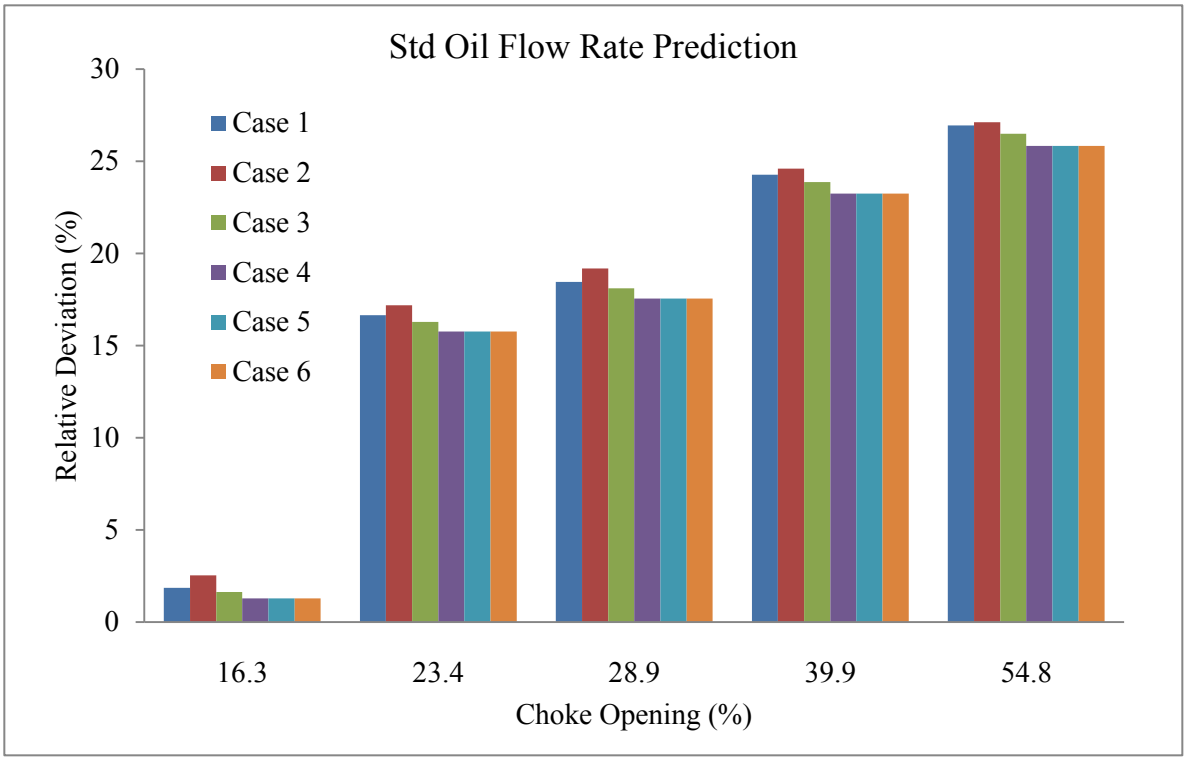

Figure 13. Oil Flow Rate Prediction, Company C

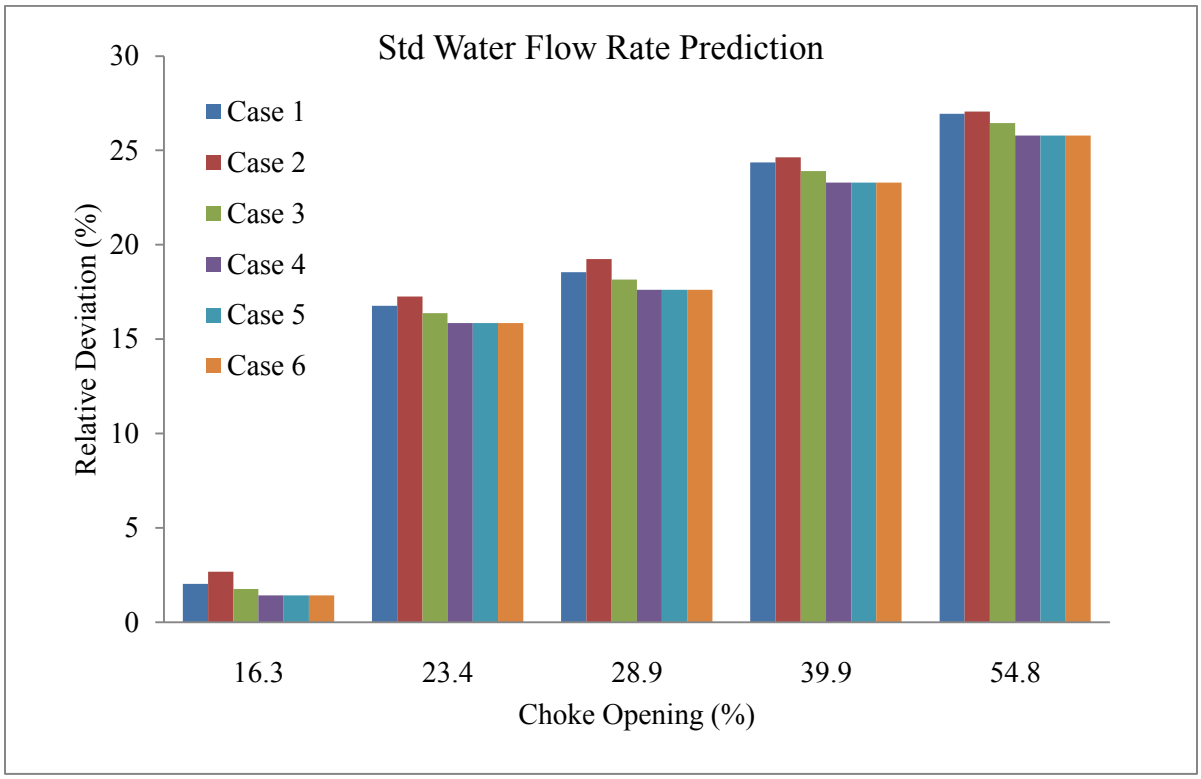

Figure 14. Water Flow Rate Prediction, Company C

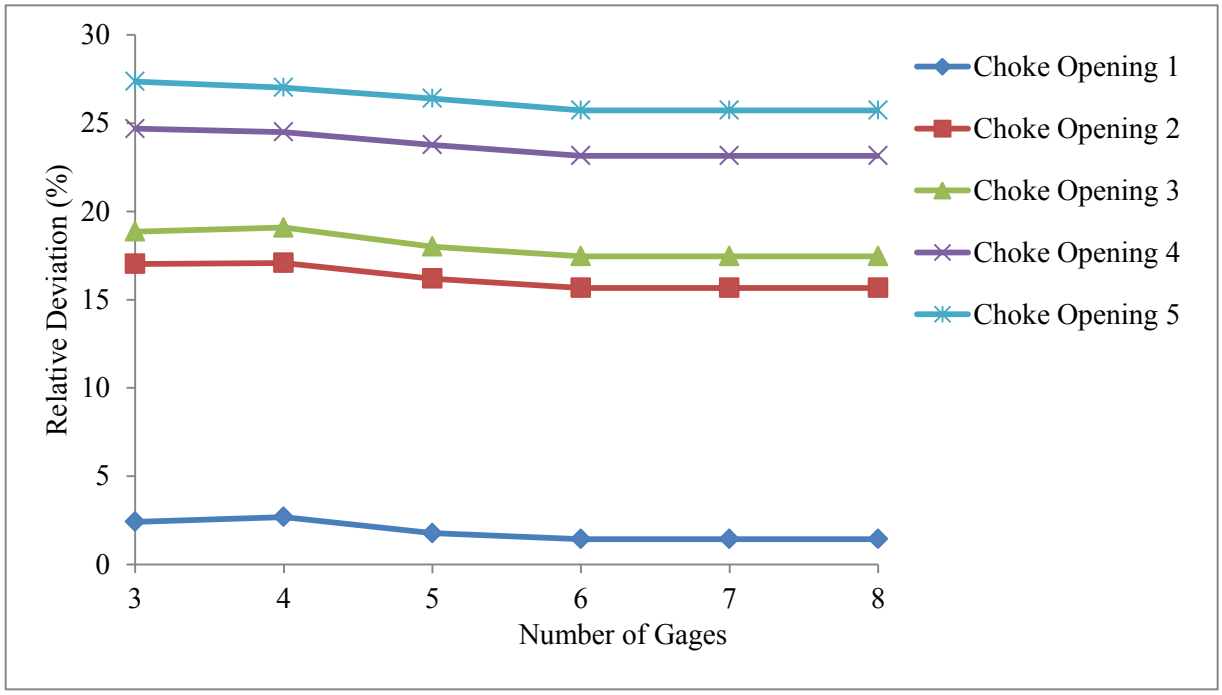

Figure 15. Relative Deviation vs. Number of Gages for Gas Prediction, Company C

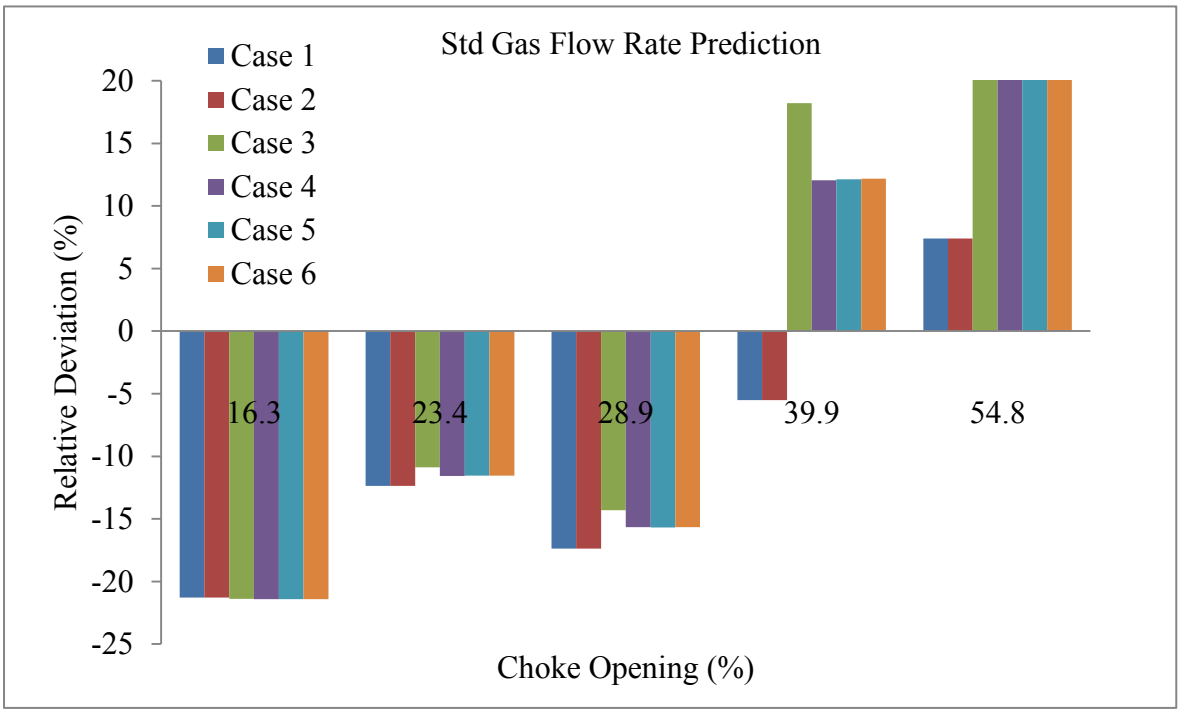

Figure 16. Gas Flow Rate Prediction, Company E

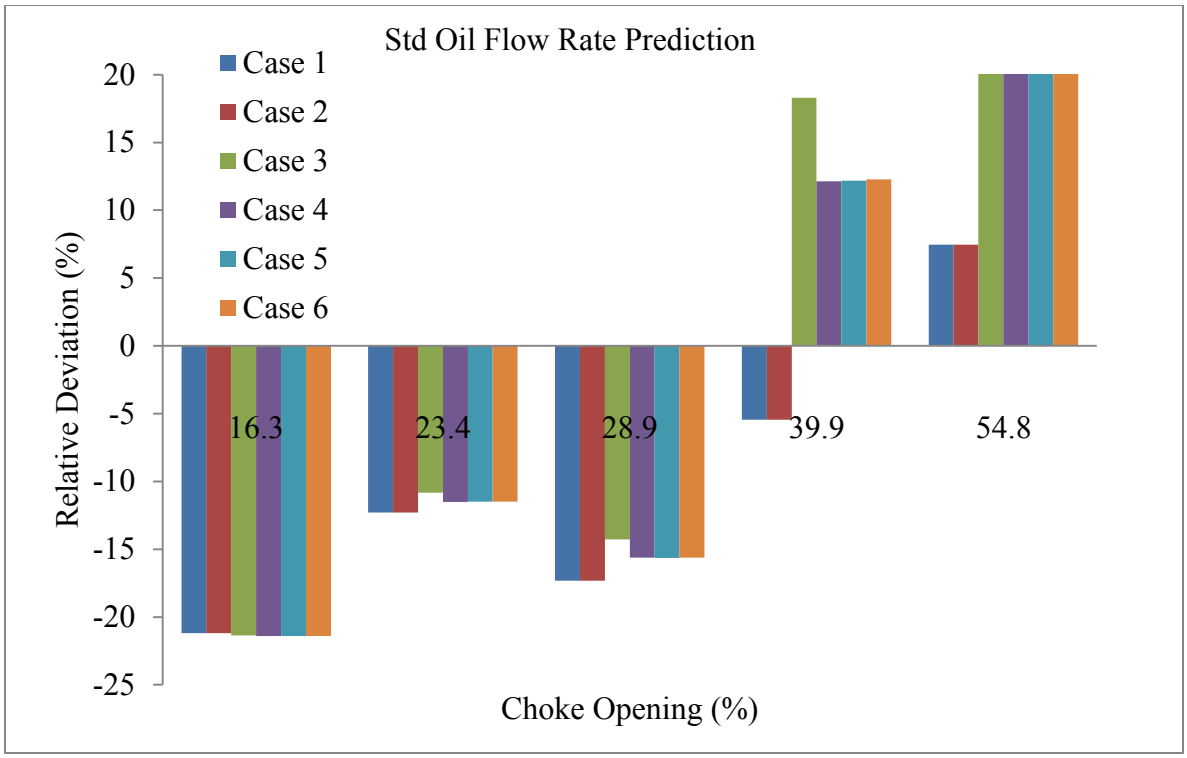

Figure 17. Oil Flow Rate Prediction, Company E

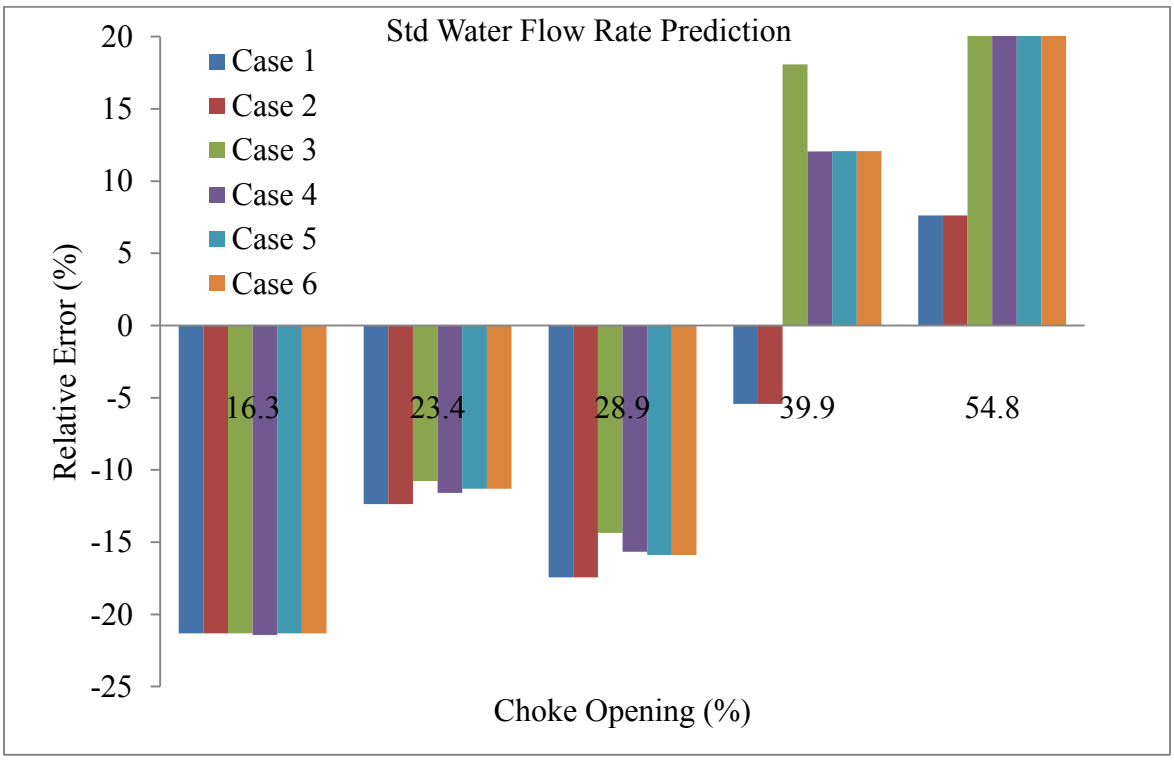

Figure 18. Water Flow Rate Prediction, Company E

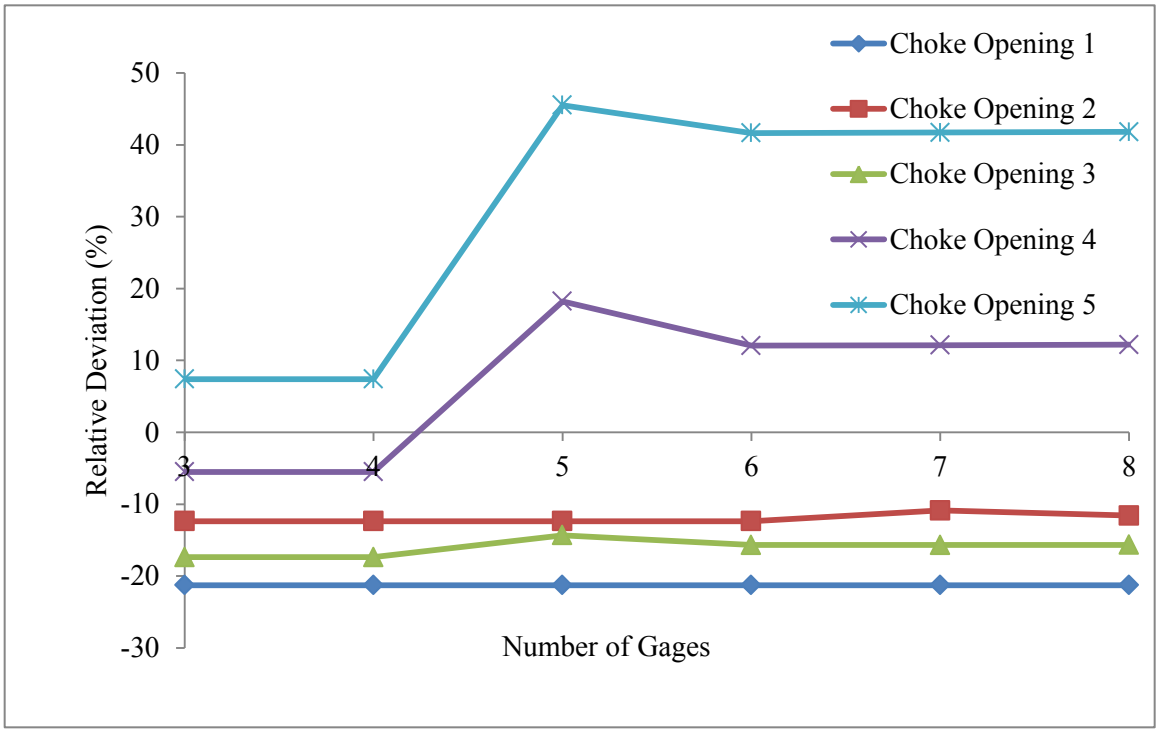

Figure 19. Relative Deviation vs. Number of Gages for Gas Prediction, Company E

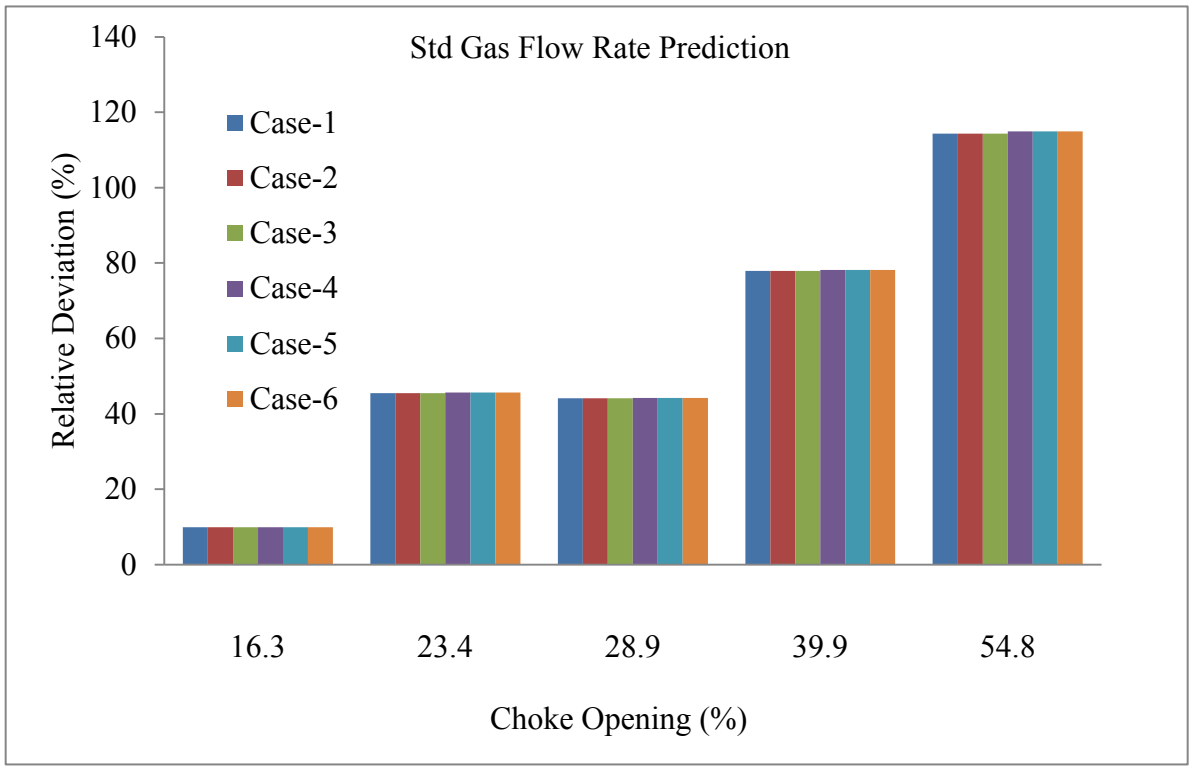

Figure 20. Gas Flow Rate Prediction, Company F

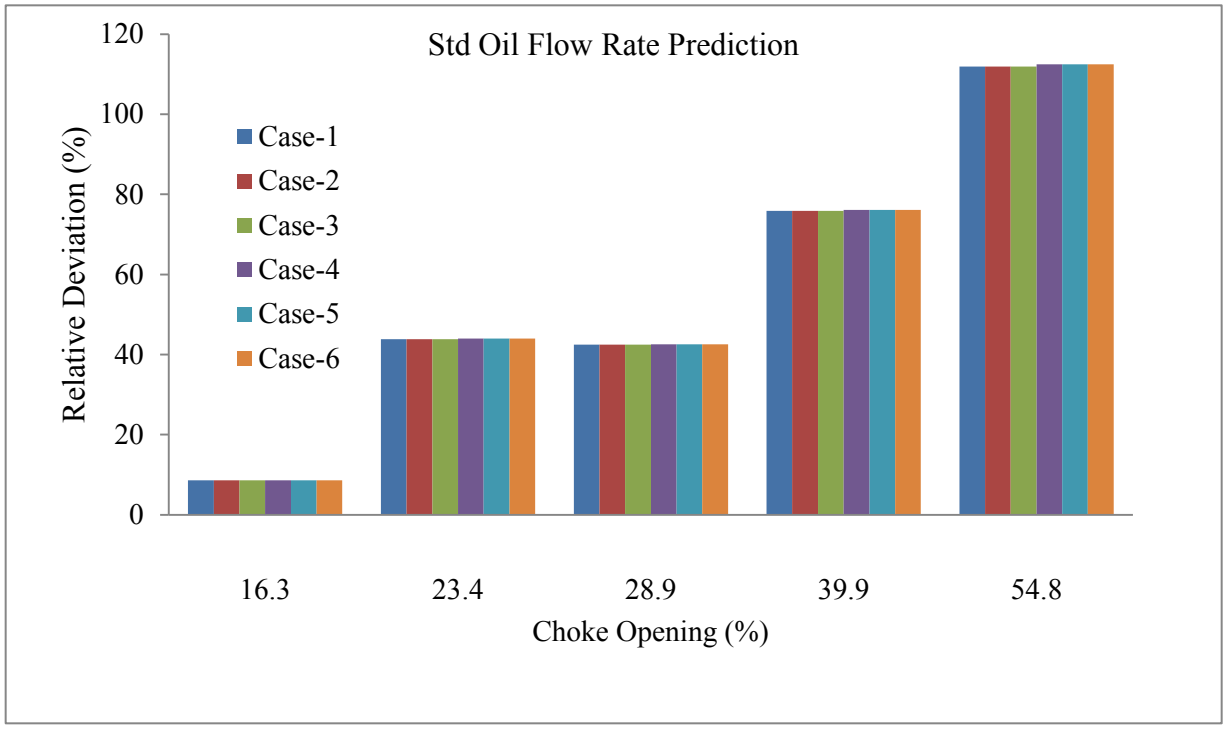

Figure 21. Oil Flow Rate Prediction, Company F

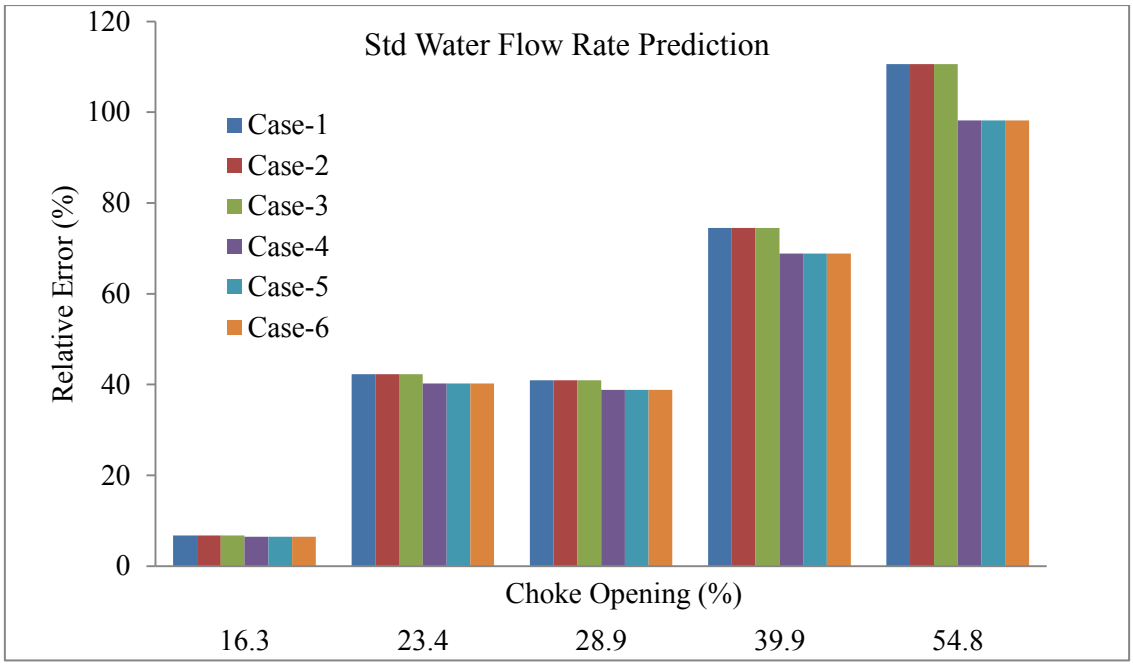

Figure 22. Water Flow Rate Prediction, Company F

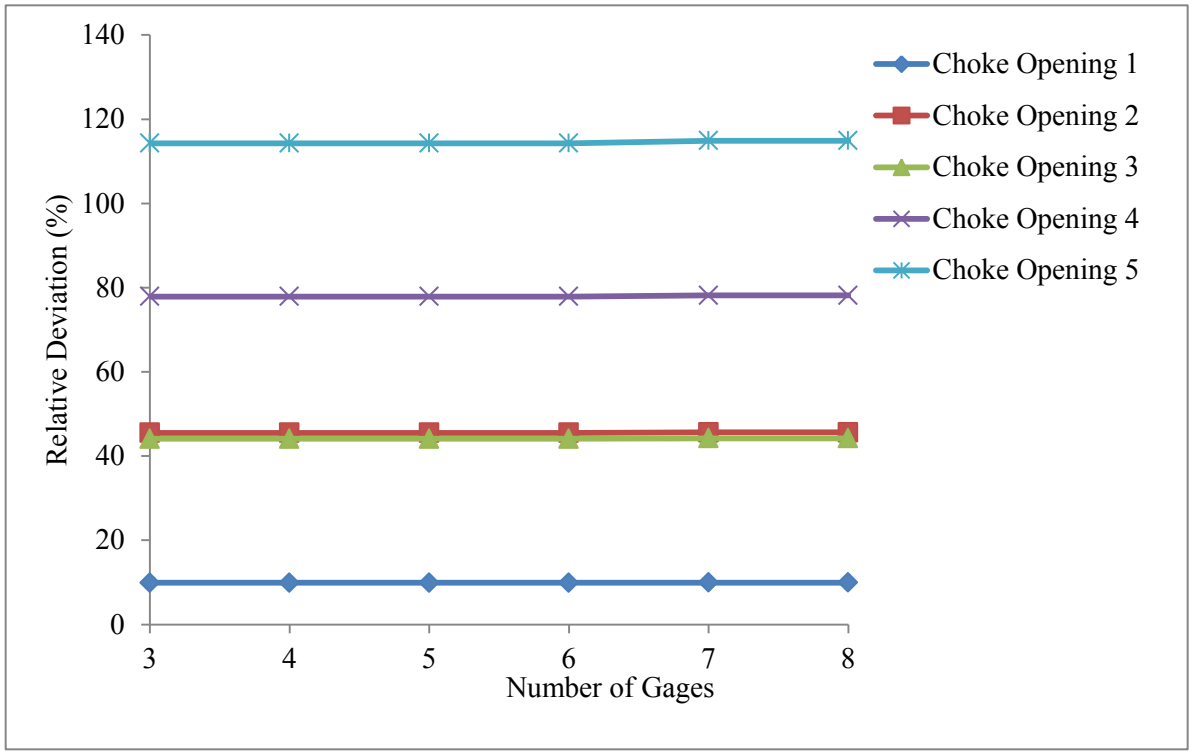

Figure 23. Relative Deviation vs. Number of Gages for Gas Prediction, Company F

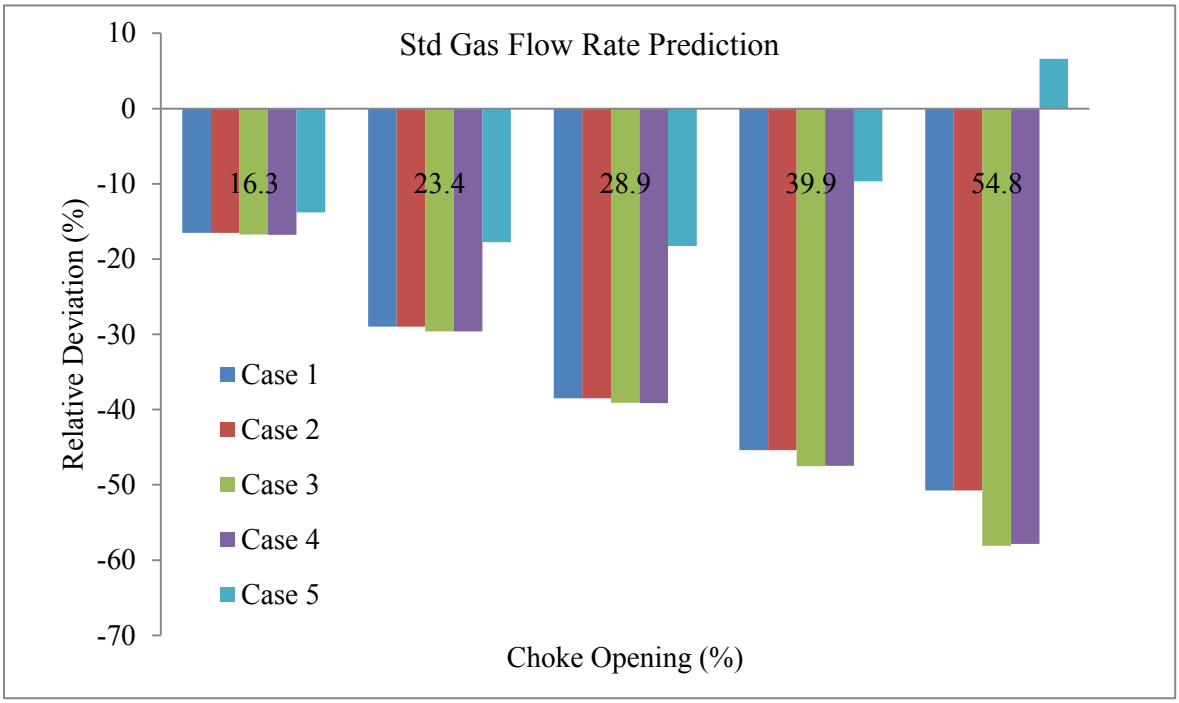

Figure 24. Gas Flow Rate Prediction, Company H

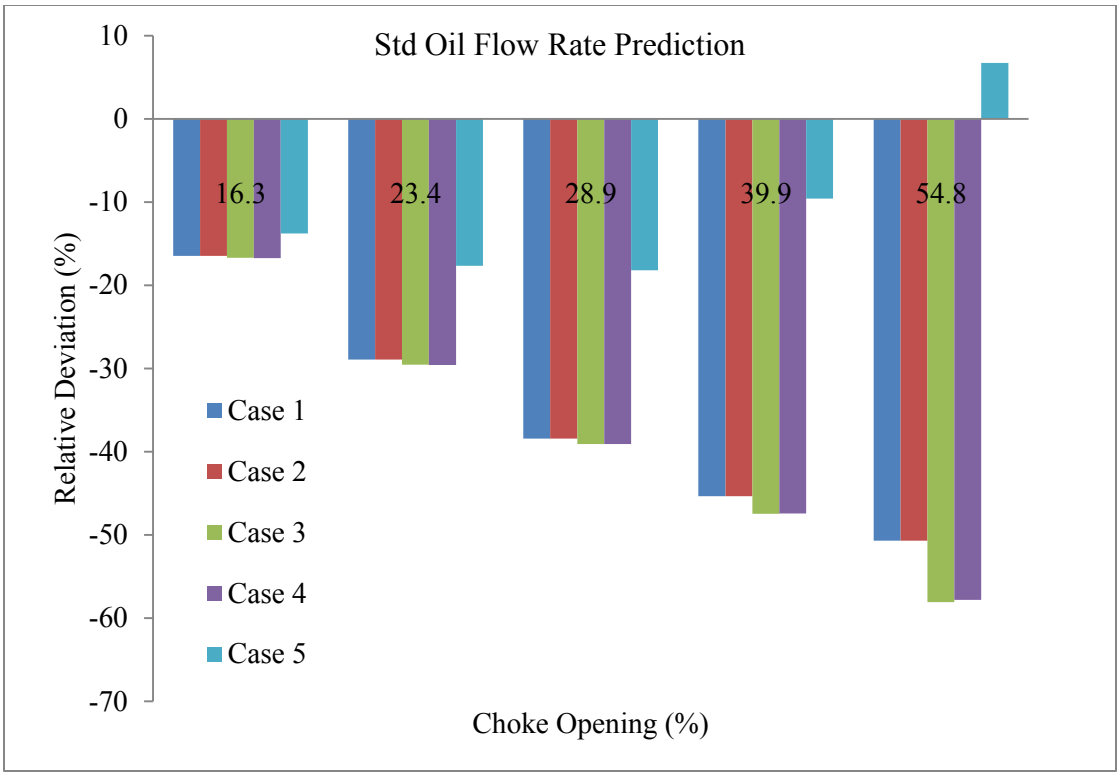

Figure 25. Oil Flow Rate Prediction, Company H

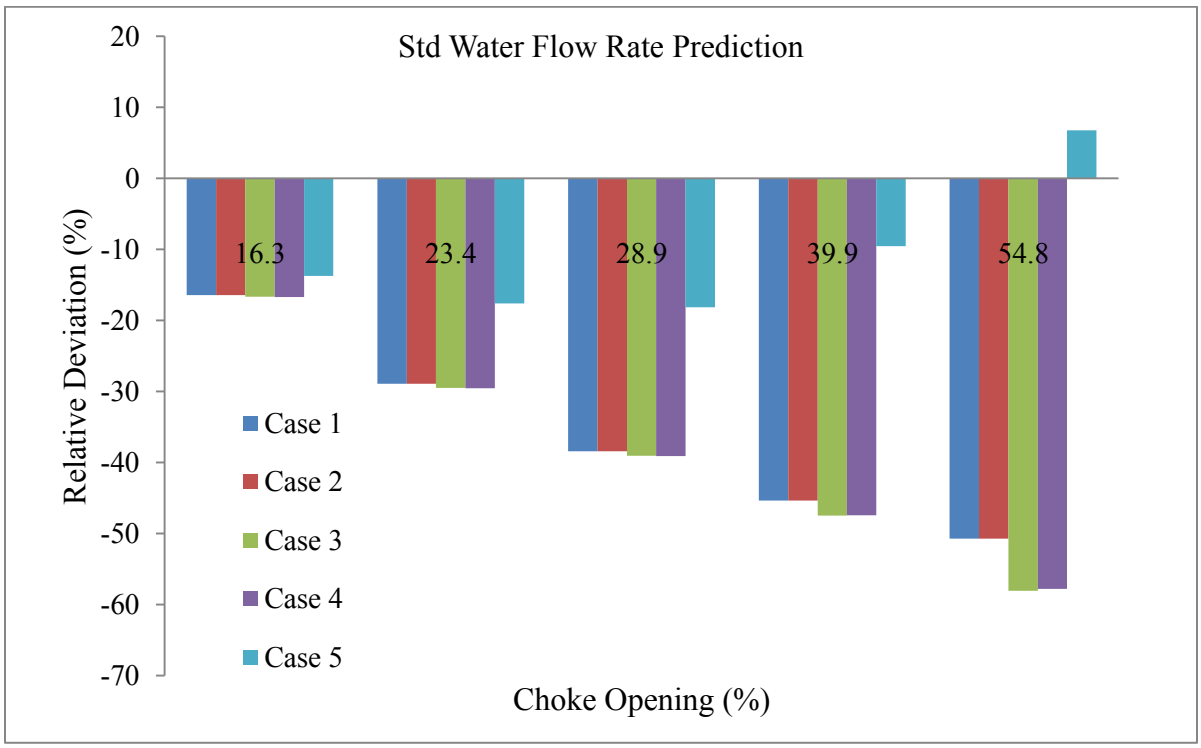

Figure 26. Water Flow Rate Prediction, Company H

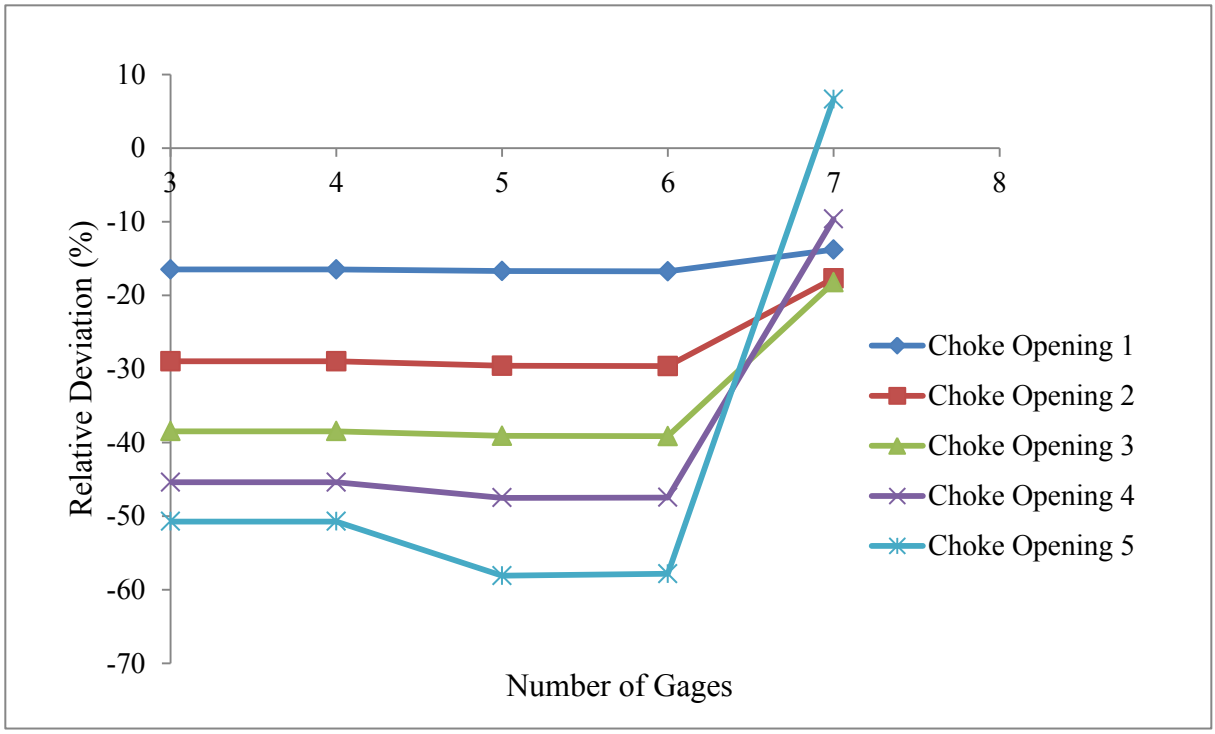

Figure 27. Relative Deviation vs. Number of Gages for Gas Prediction, Company F

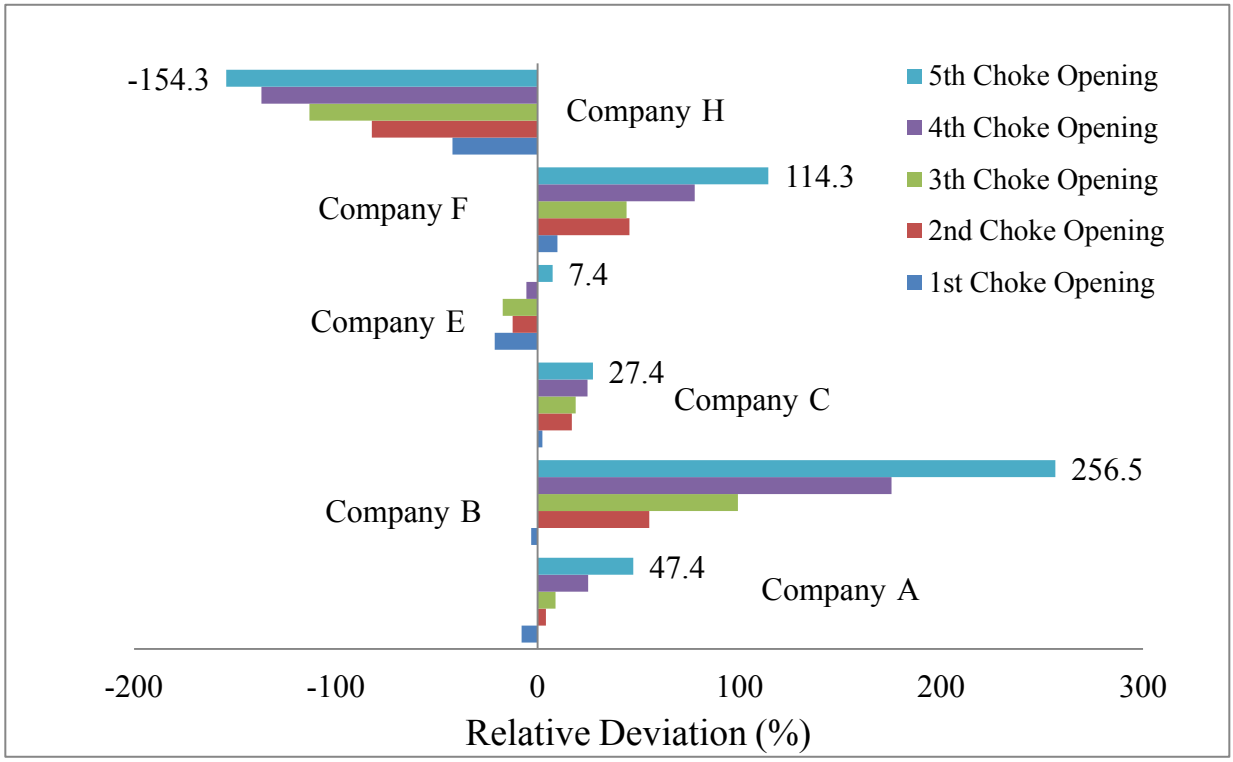

Figure 28. Gas Flow Rate Prediction Comparisons, Case 1

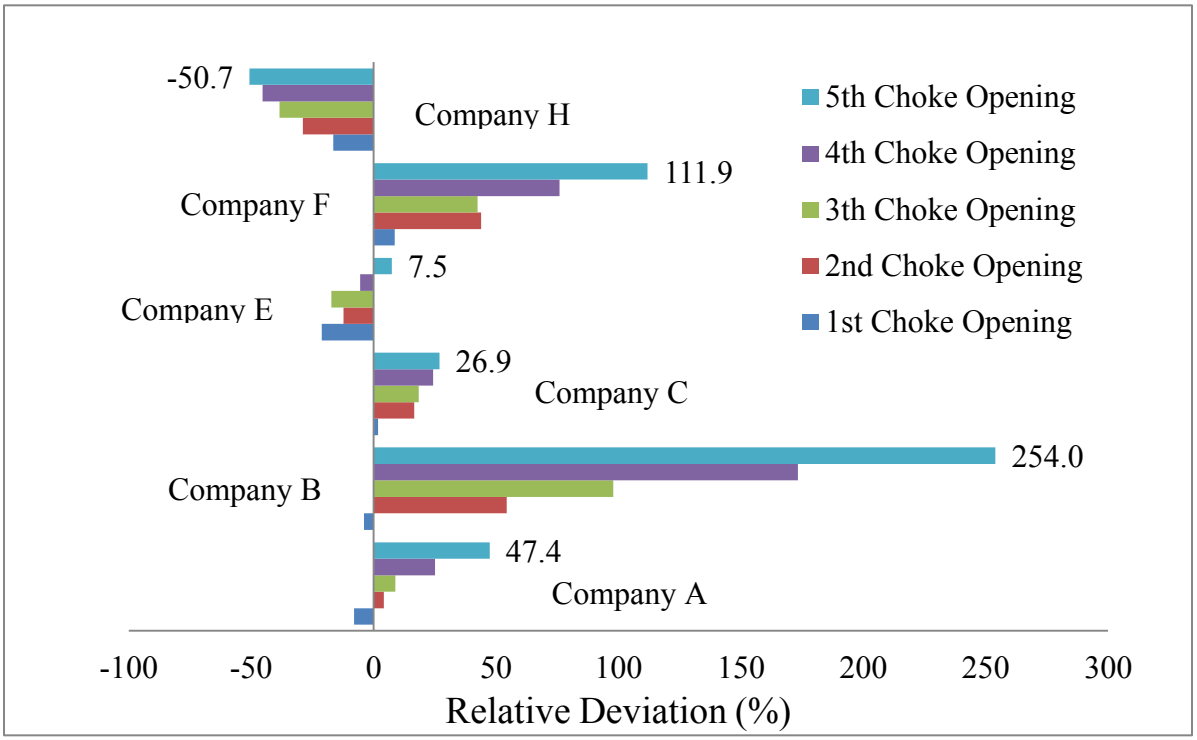

Figure 29. Oil Flow Rate Prediction Comparisons, Case 1

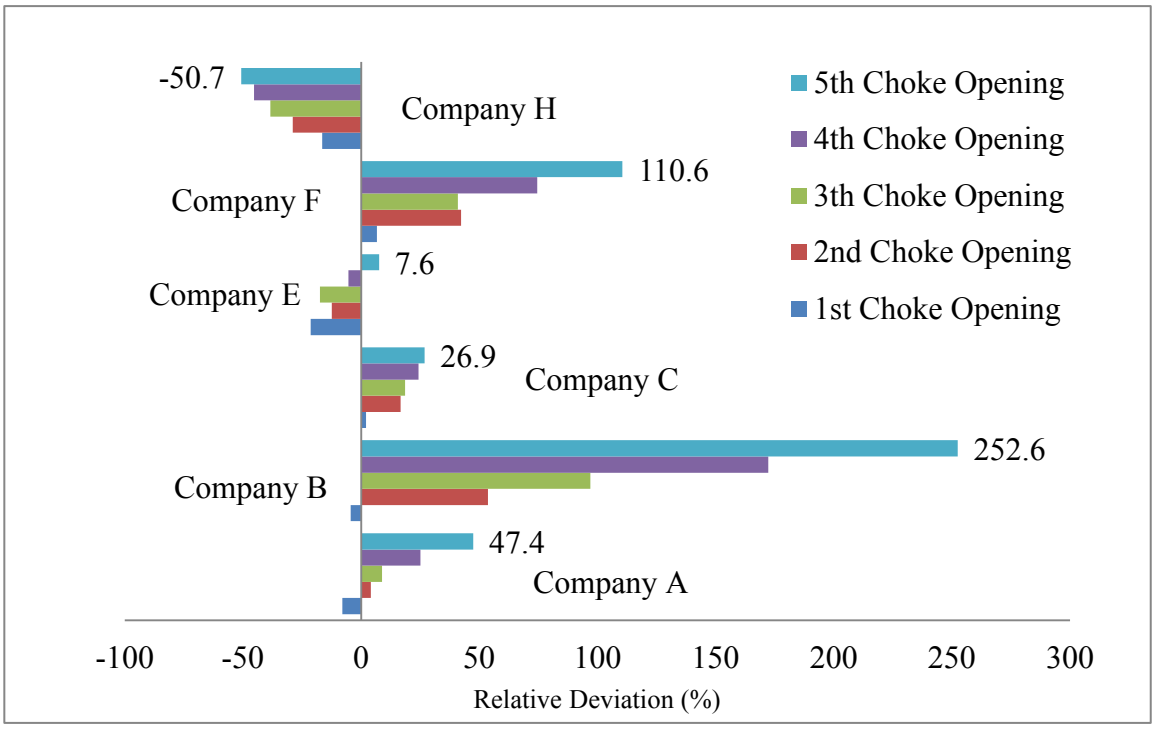

Figure 30. Water Flow Rate Prediction Comparisons, Case 1

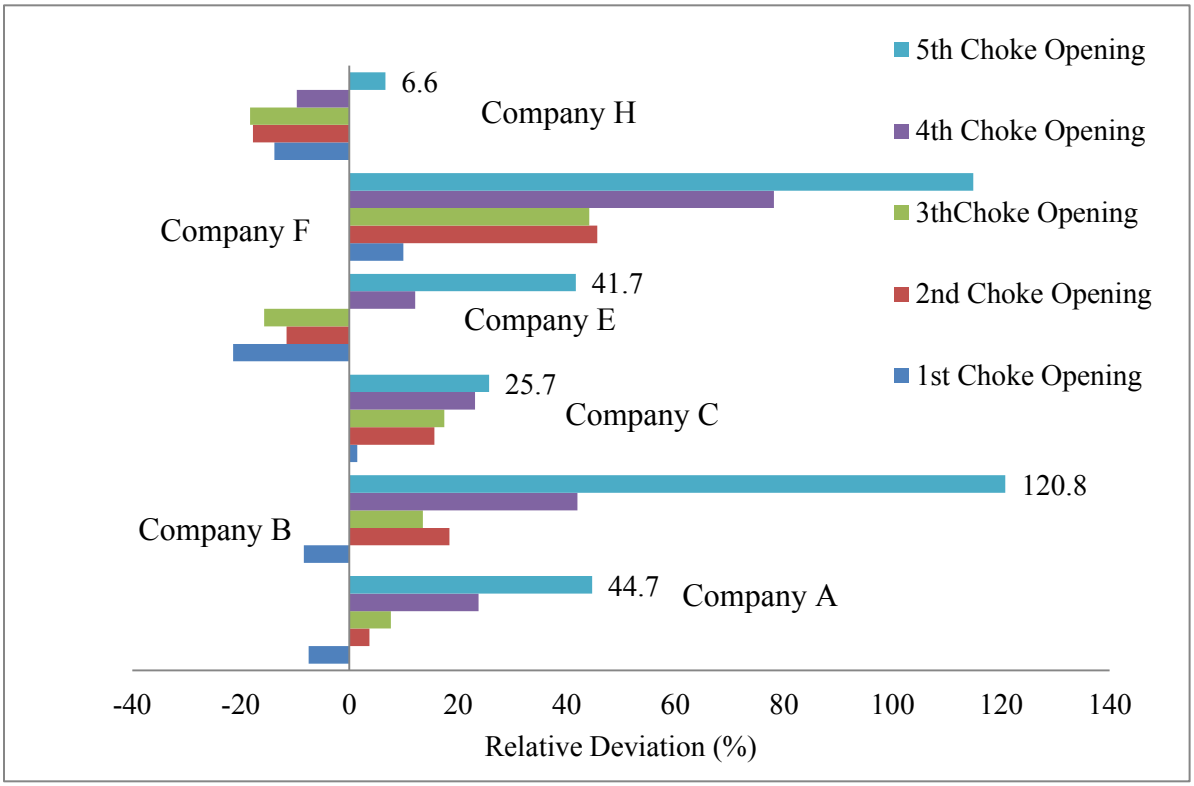

Figure 31. Gas Flow Rate Prediction Comparisons, Case 5

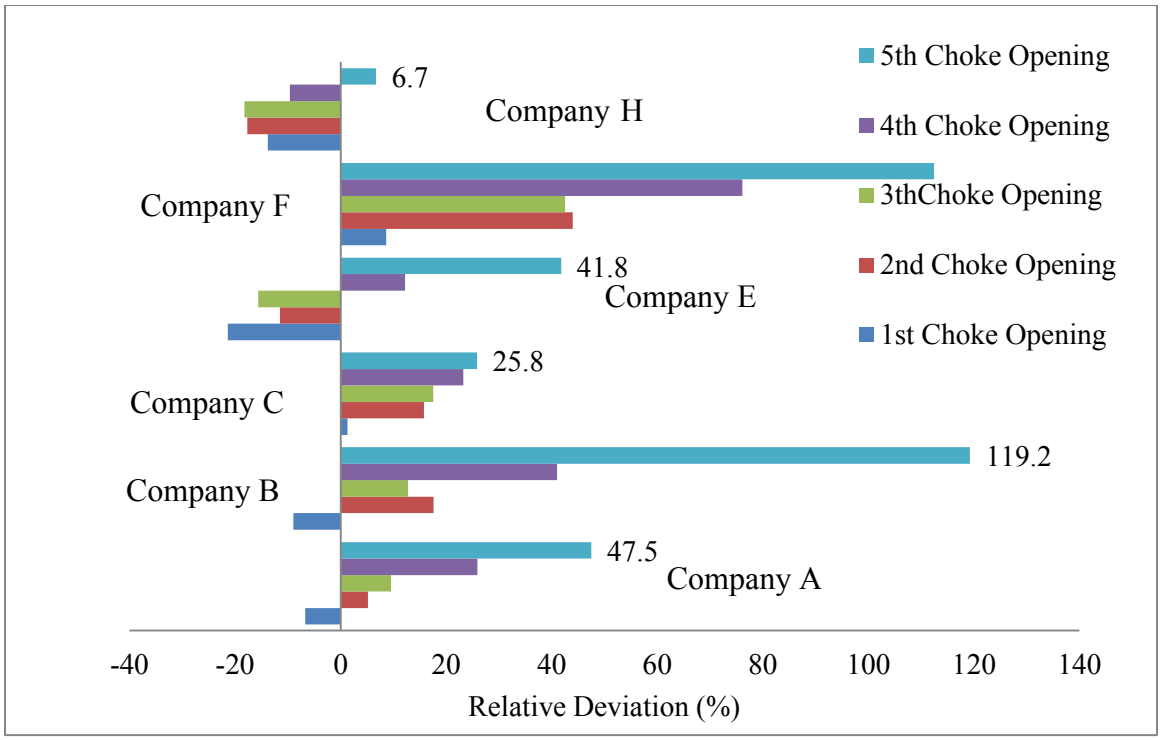

Figure 32. Oil Flow Rate Prediction Comparisons, Case 5

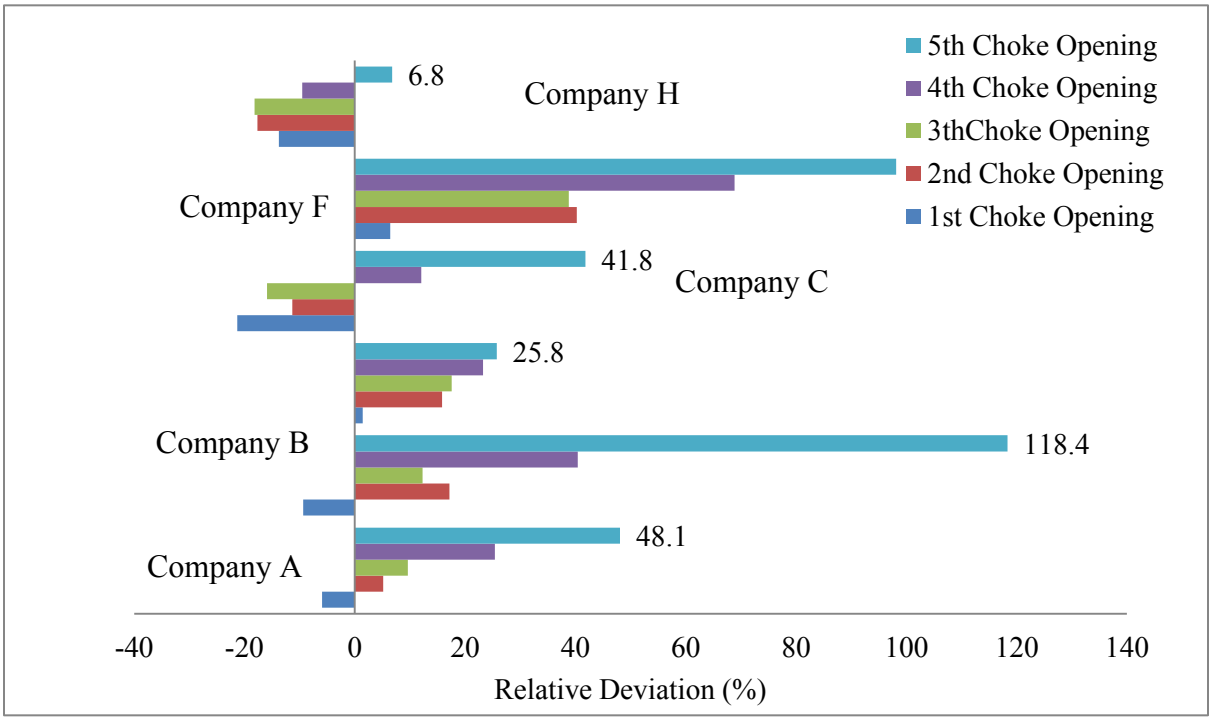

Figure 33. Water Flow Rate Prediction Comparisons, Case 5

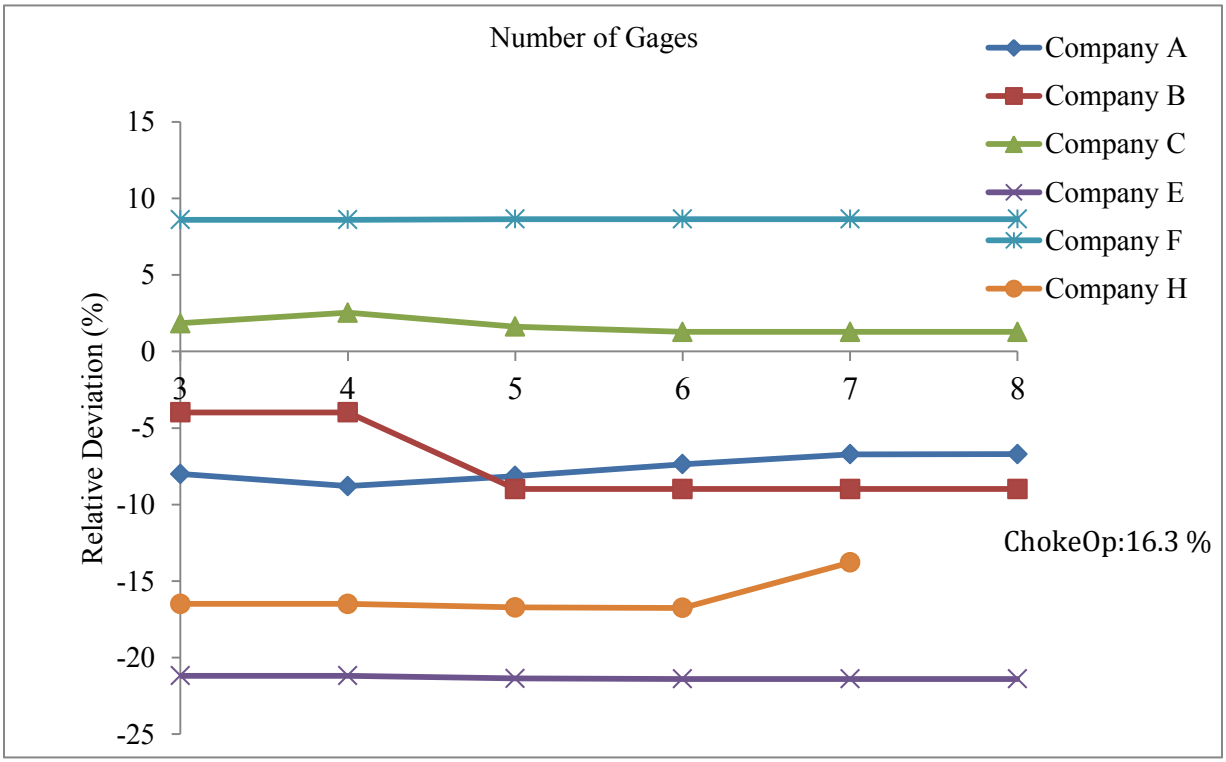

Figure 34. Company Comparisons for Oil Prediction, Choke Opening: 16.3%

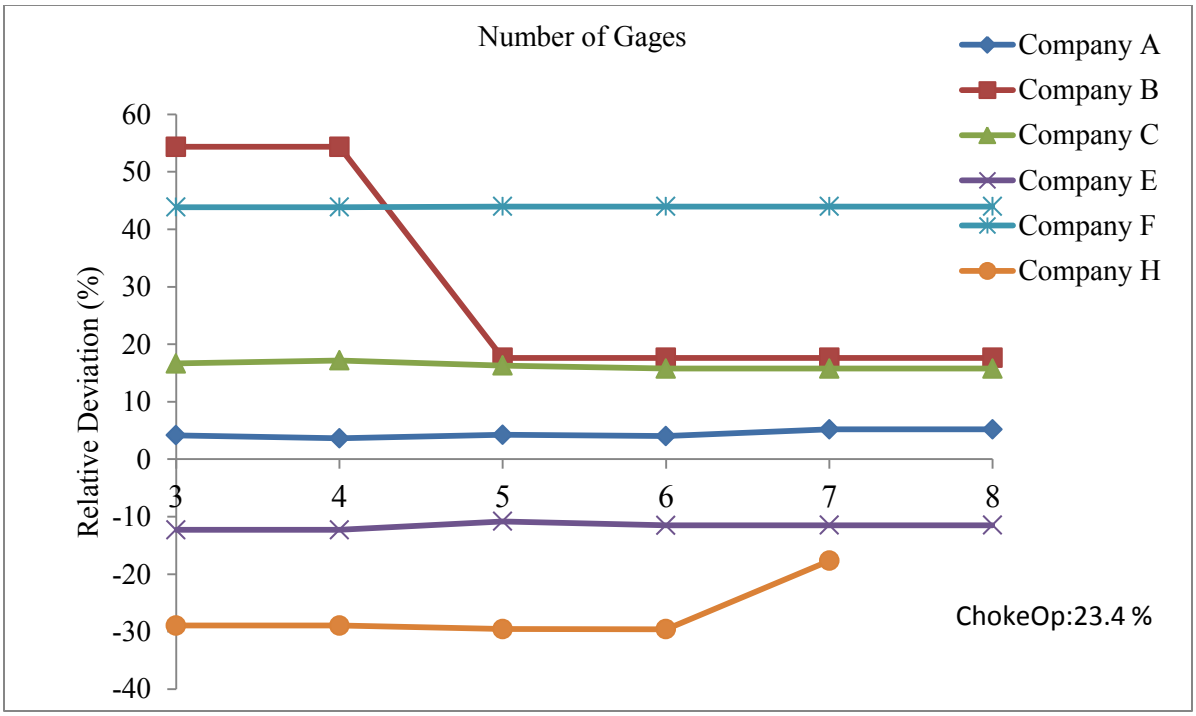

Figure 35. Company Comparisons for Oil Prediction, Choke Opening: 23,4%

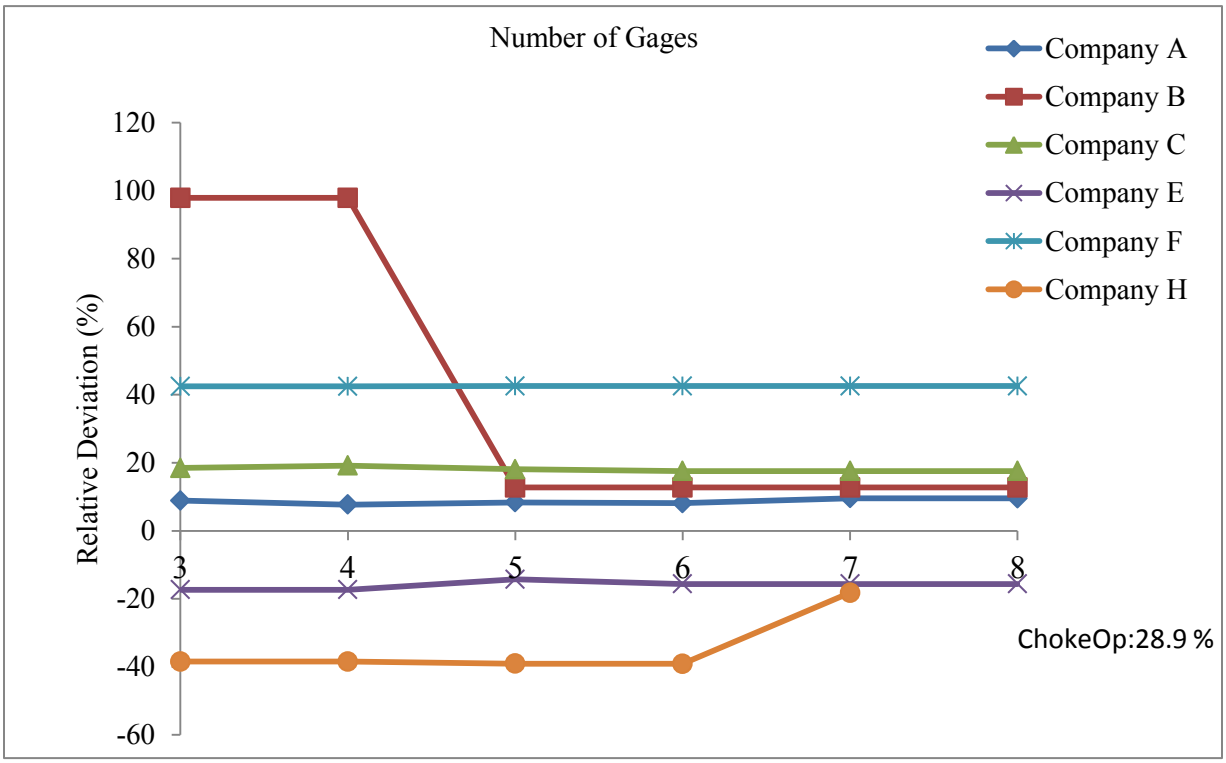

Figure 36. Company Comparisons for Oil Prediction, Choke Opening: 28,9%

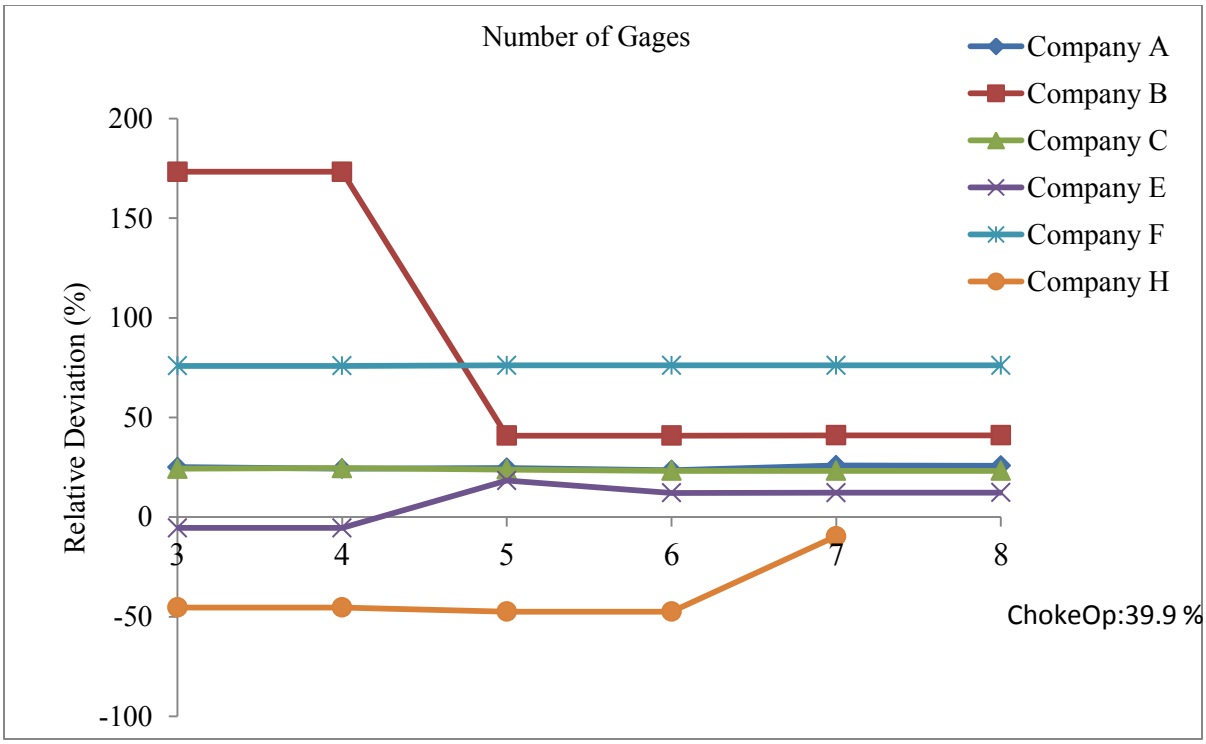

Figure 37. Company Comparisons for Oil Prediction, Choke Opening: 39,9 %

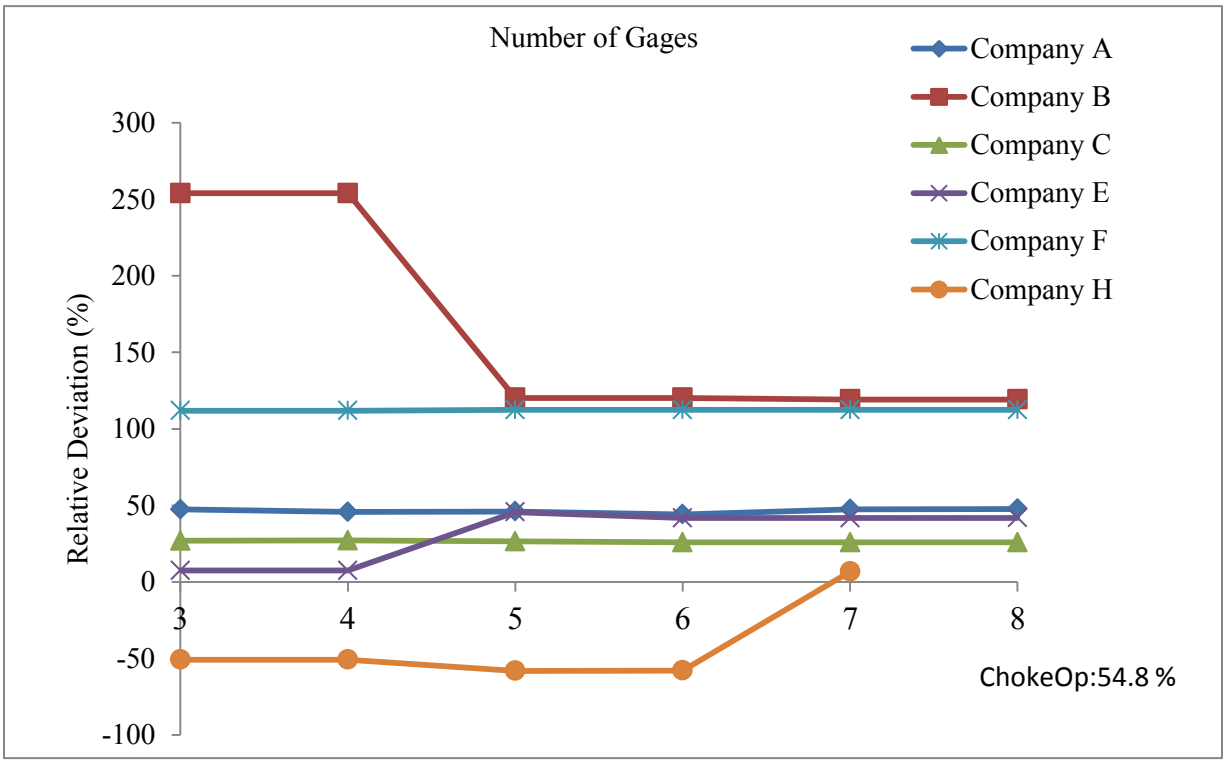

Figure 38. Company Comparisons for Oil Prediction, Choke Opening: 54,8 %

Round 2 Results

Similar to Round 1, relative deviation percentages are plotted for each company. Figures 39 through 46 are histograms for Company A and Company C for gas, oil and water predictions. Figures 42 and 46 are relative deviation versus different cases all days. Tuning improved the predictions for the cases.

Figures 47 through 52 gives comparisons of Company A and C results. Figures 47 through 49 are comparisons for Case 1 gas, oil and water predictions. Figures 50 through 52 are comparisons for Case 5.

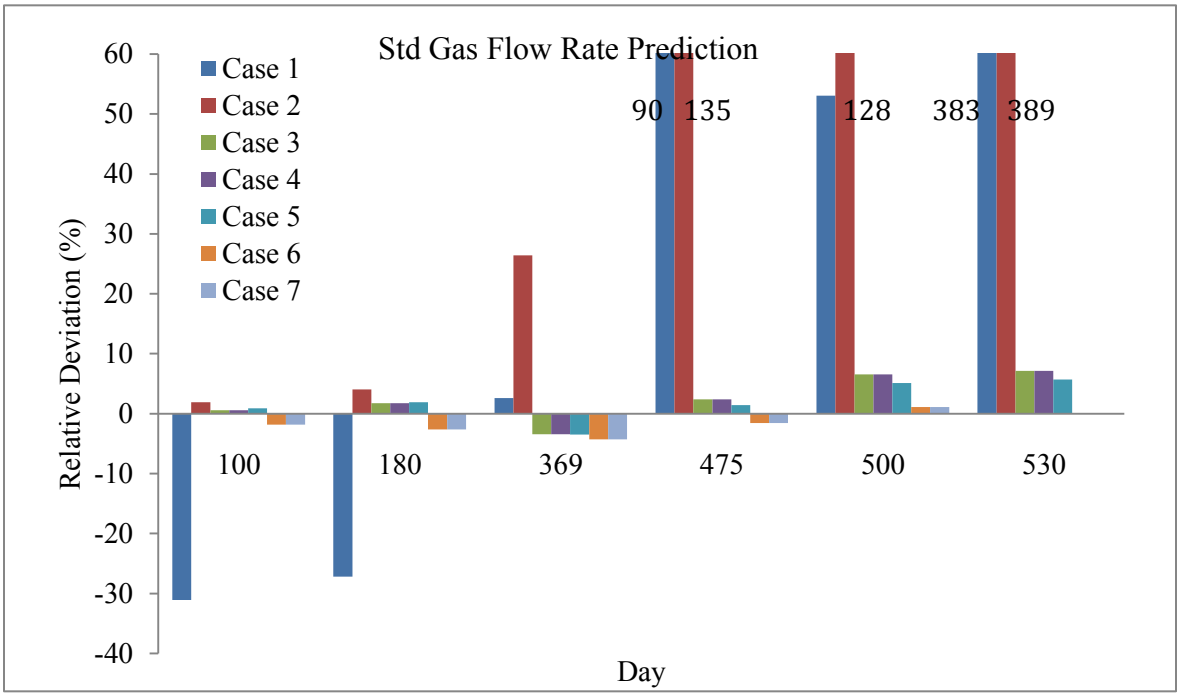

Figure 39. Gas Flow Rate Prediction, Company A

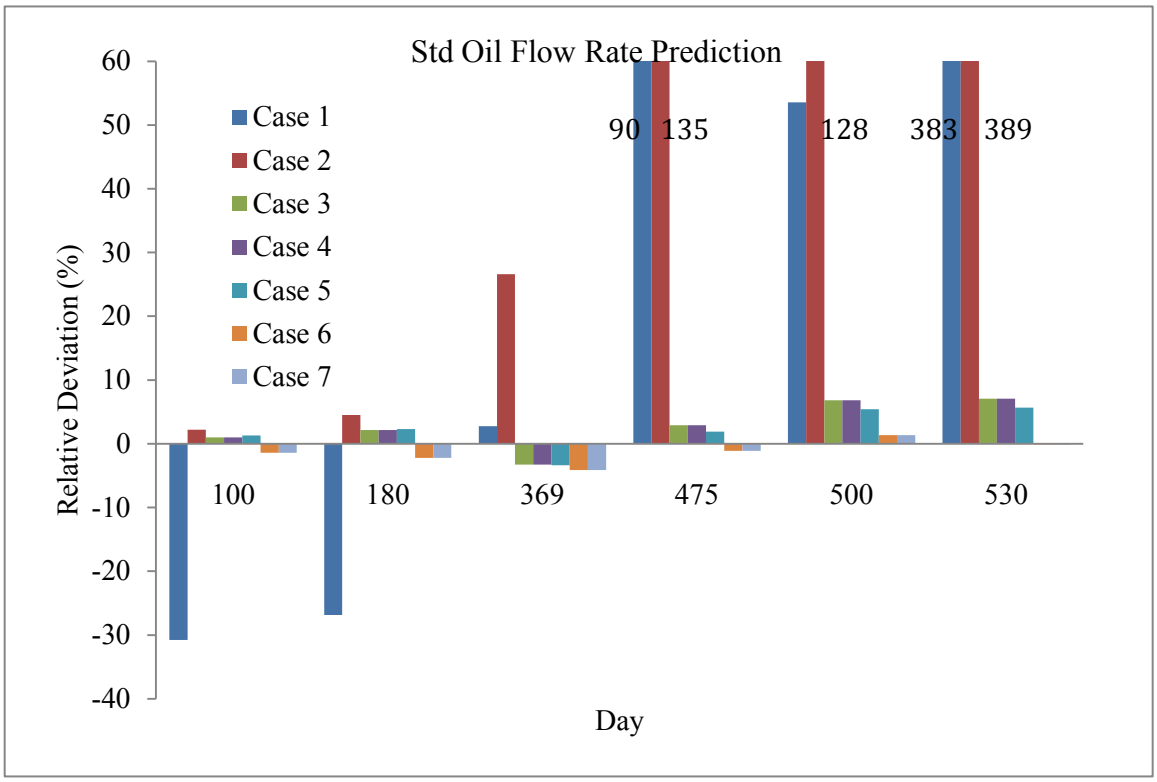

Figure 40. Oil Flow Rate Prediction, Company A

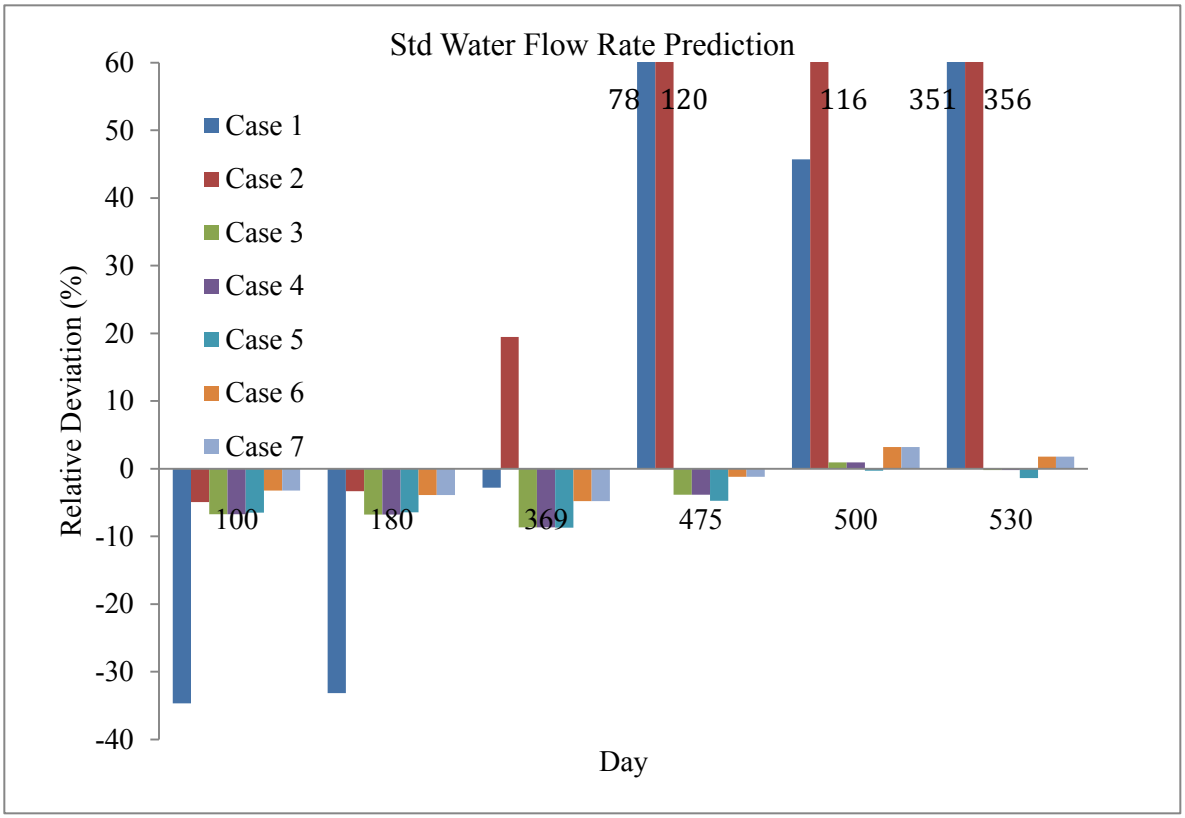

Figure 41. Water Flow Rate Prediction, Company A

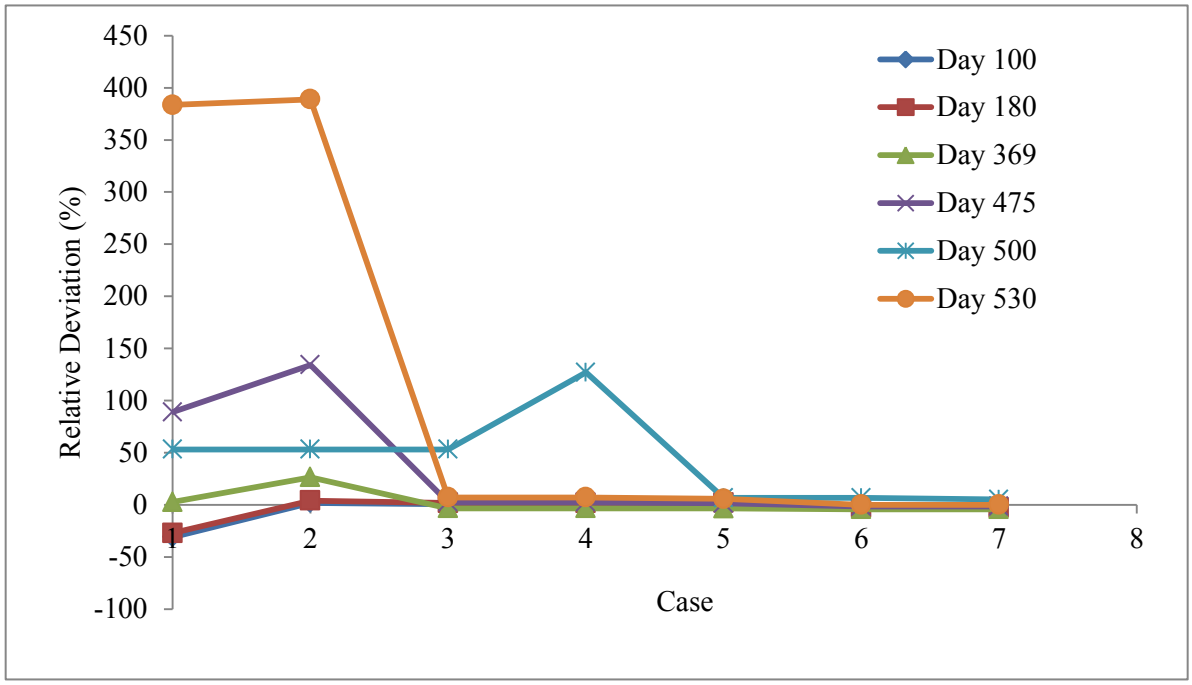

Figure 42. Relative Error vs. Cases for Gas Prediction, Company A

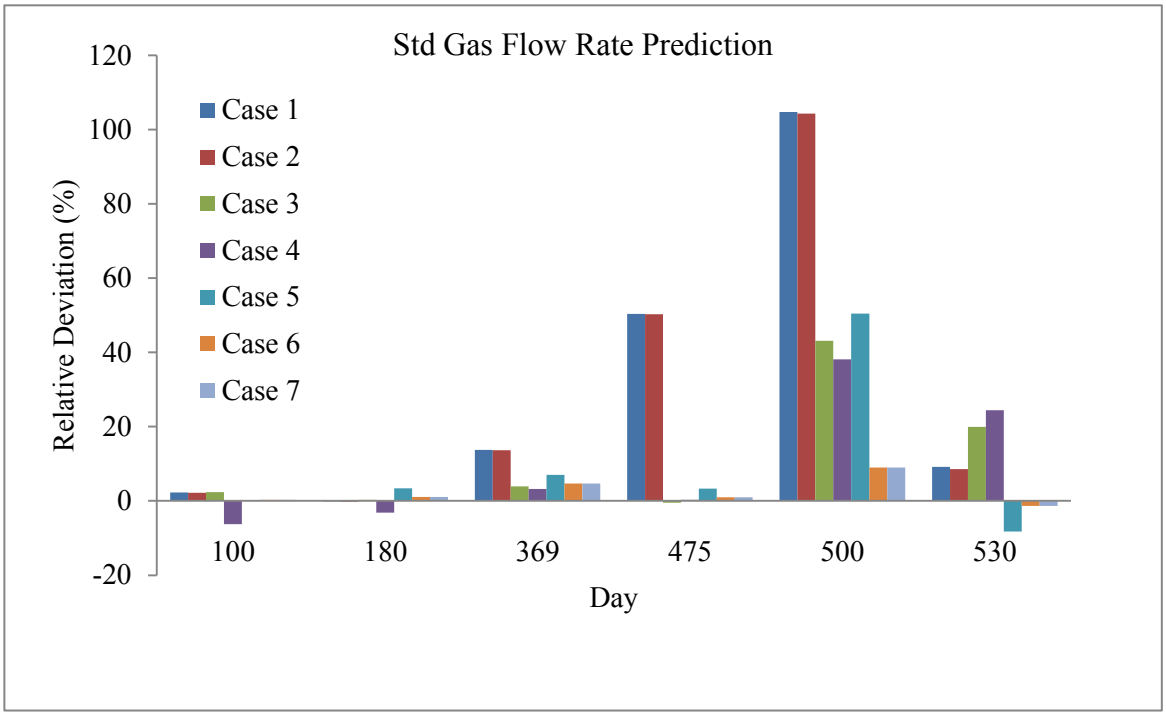

Figure 43. Gas Flow Rate Prediction, Company C

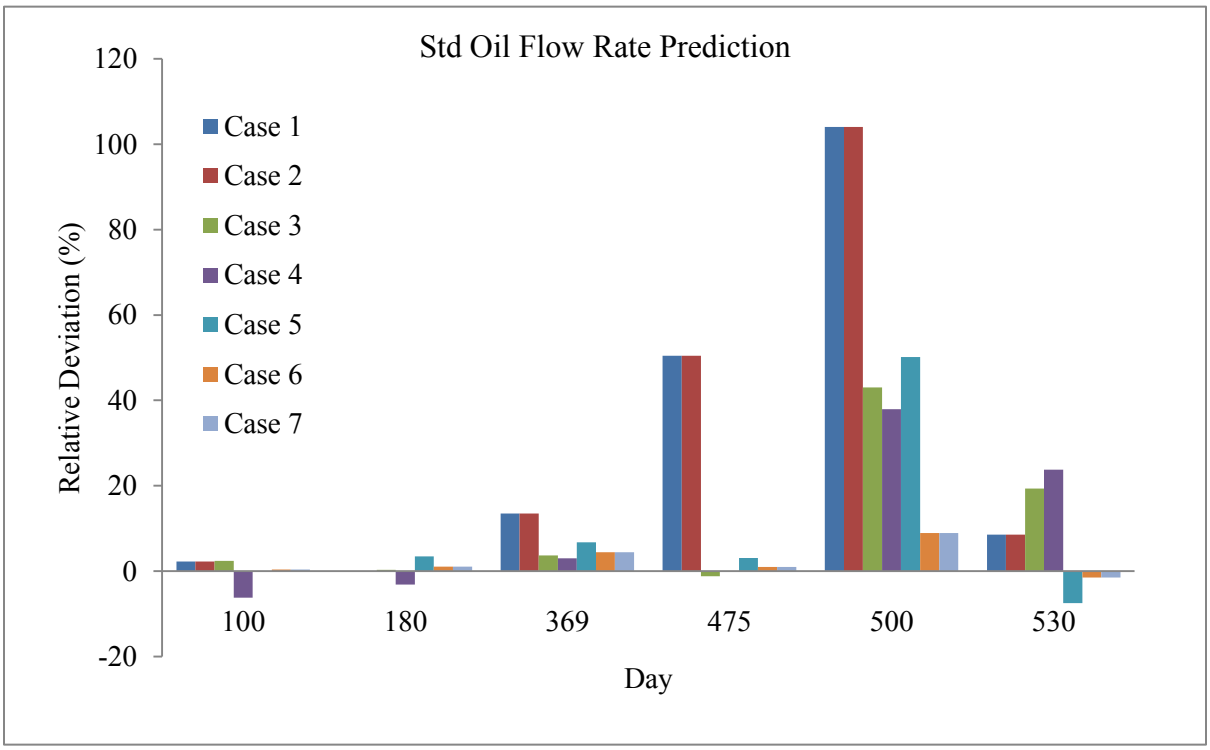

Figure 44. Oil Flow Rate Prediction, Company C

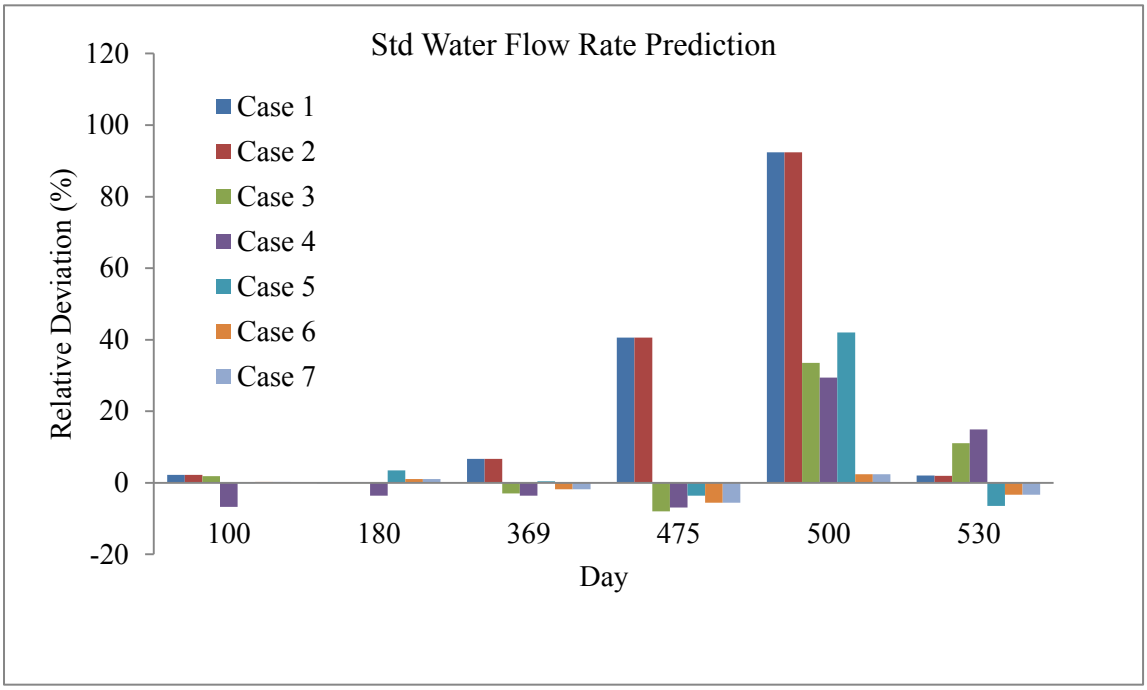

Figure 45. Water Flow Rate Prediction, Company C

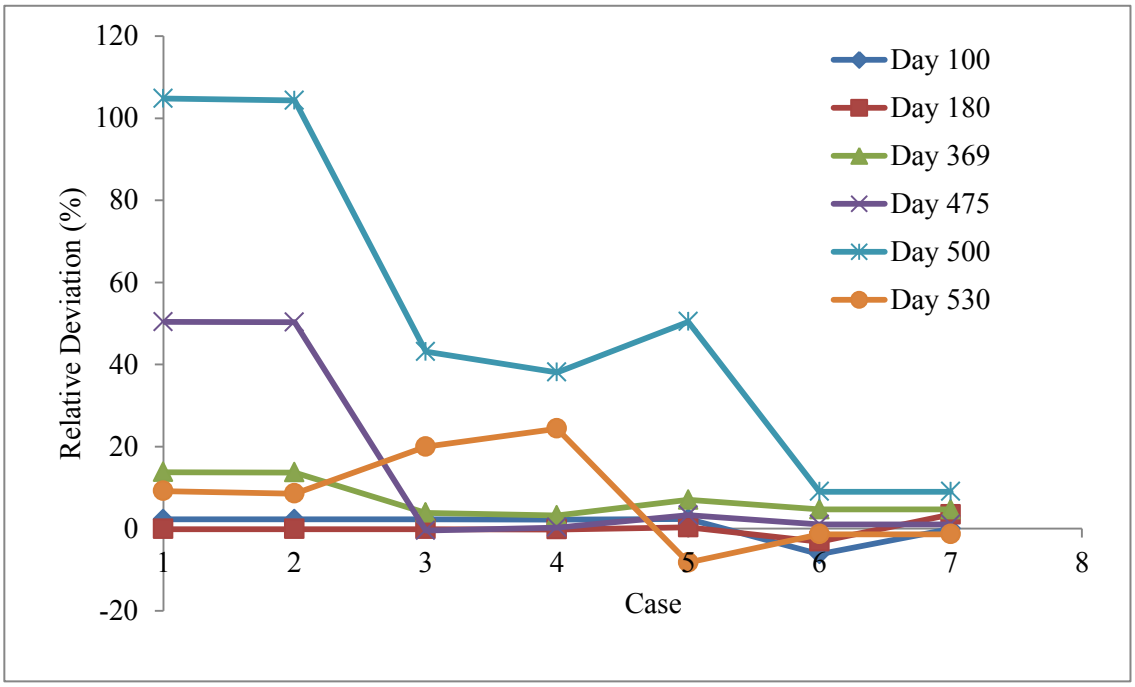

Figure 46. Relative Error vs. Cases for Gas Prediction, Company C

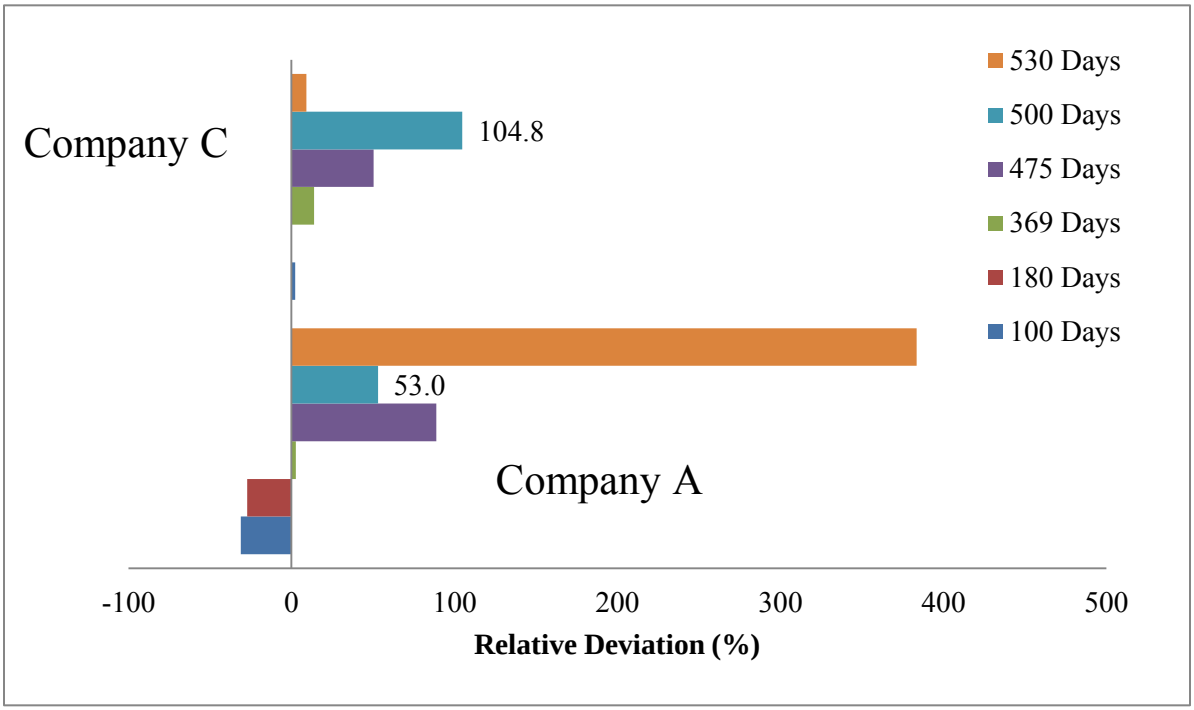

Figure 47. Gas Flow Rate Prediction Comparisons, Case 1

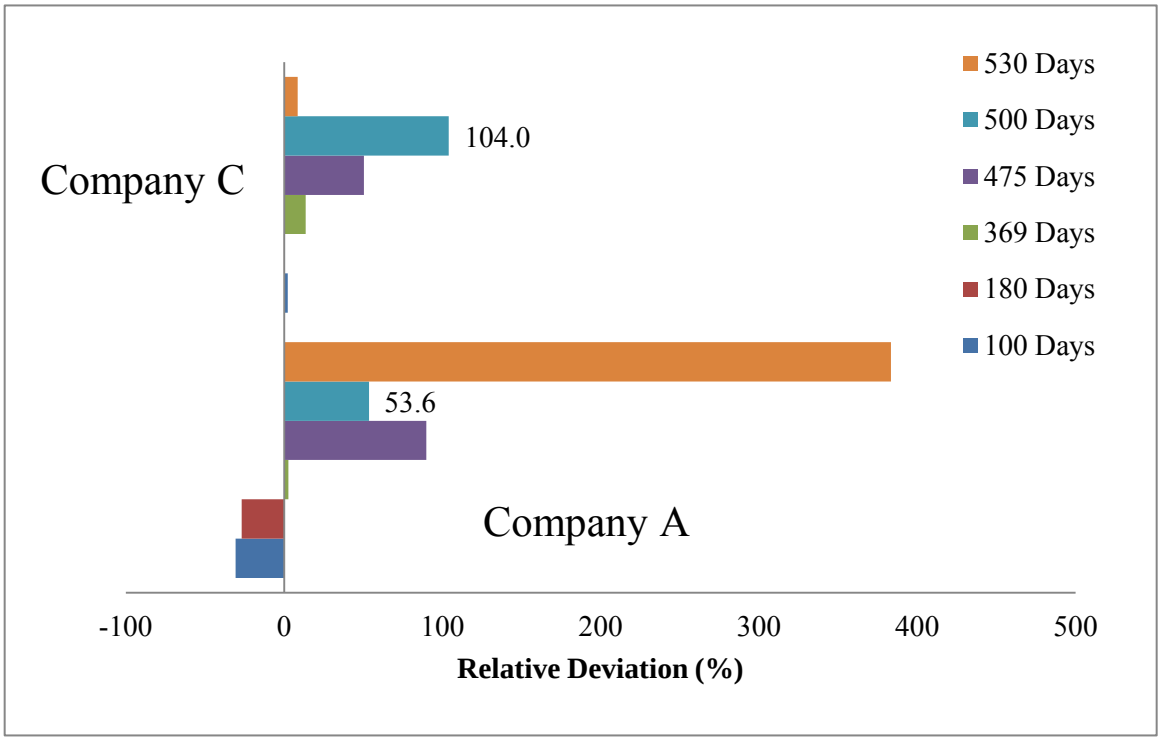

Figure 48. Oil Flow Rate Prediction Comparisons, Case 1

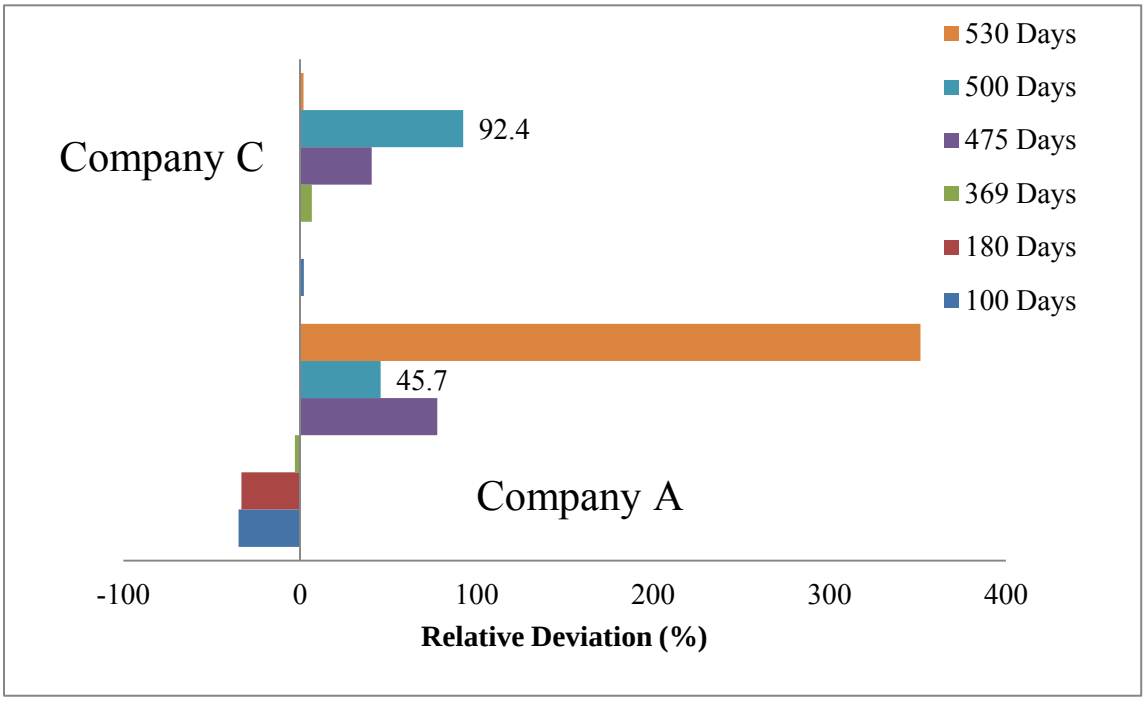

Figure 49. Water Flow Rate Prediction Comparisons, Case 1

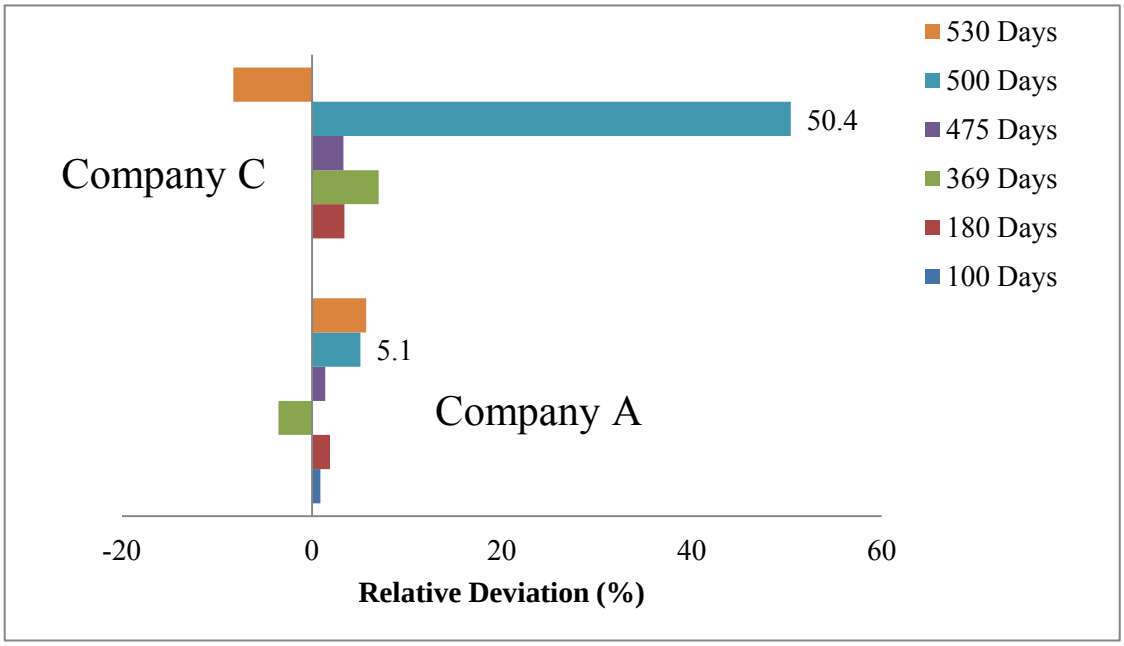

Figure 50. Gas Flow Rate Prediction Comparisons, Case 5

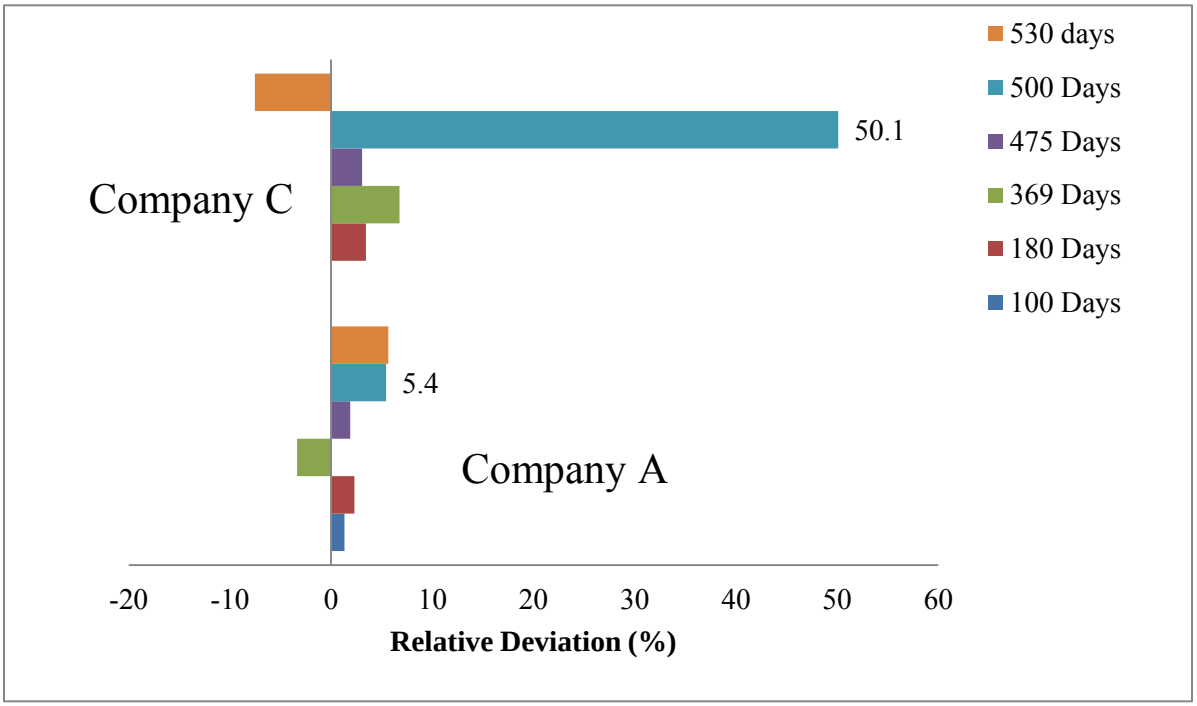

Figure 51. Oil Flow Rate Prediction Comparisons, Case 5

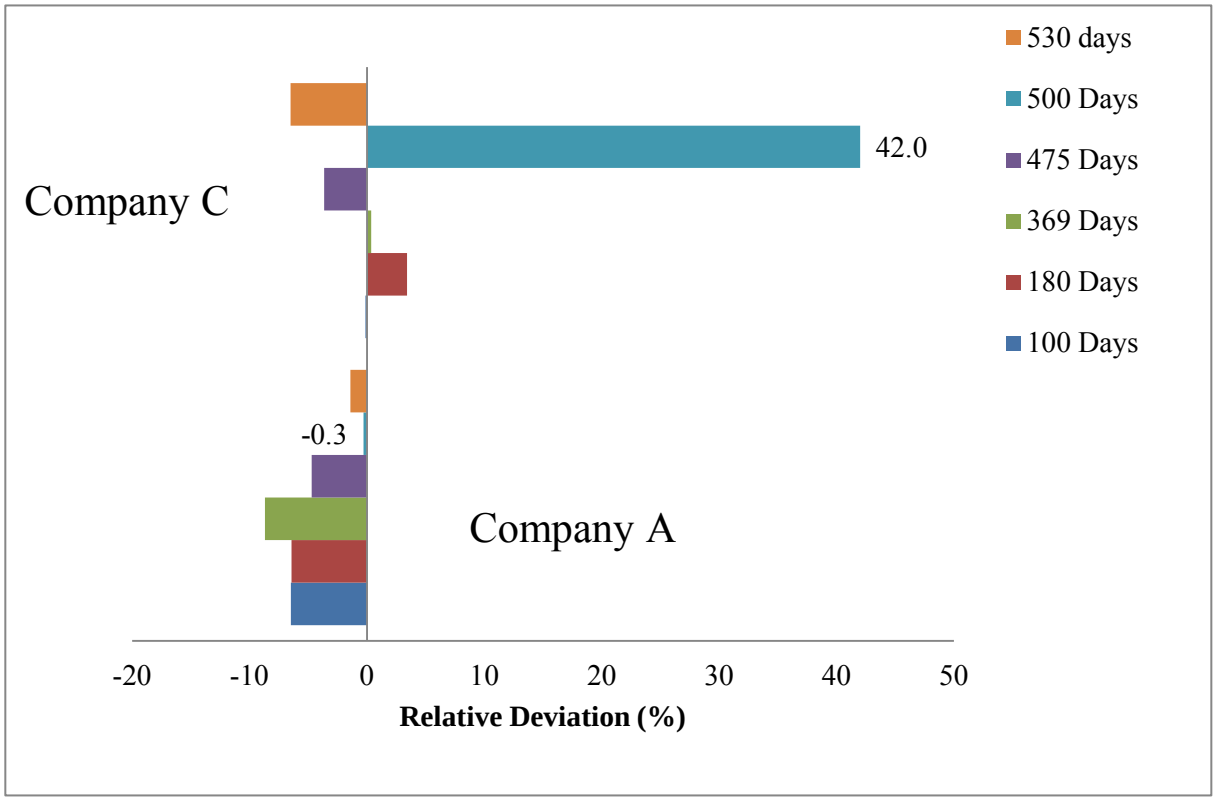

Figure 52. Water Flow Rate Prediction Comparisons, Case 5

Round 3 Results

Figures 53 through 55 gives relative deviation percentages for gas, oil and water predictions for Company A. There are 11 different sets for predictions for two valve openings. In most cases, larger valve opening increased the relative deviation for predictions.

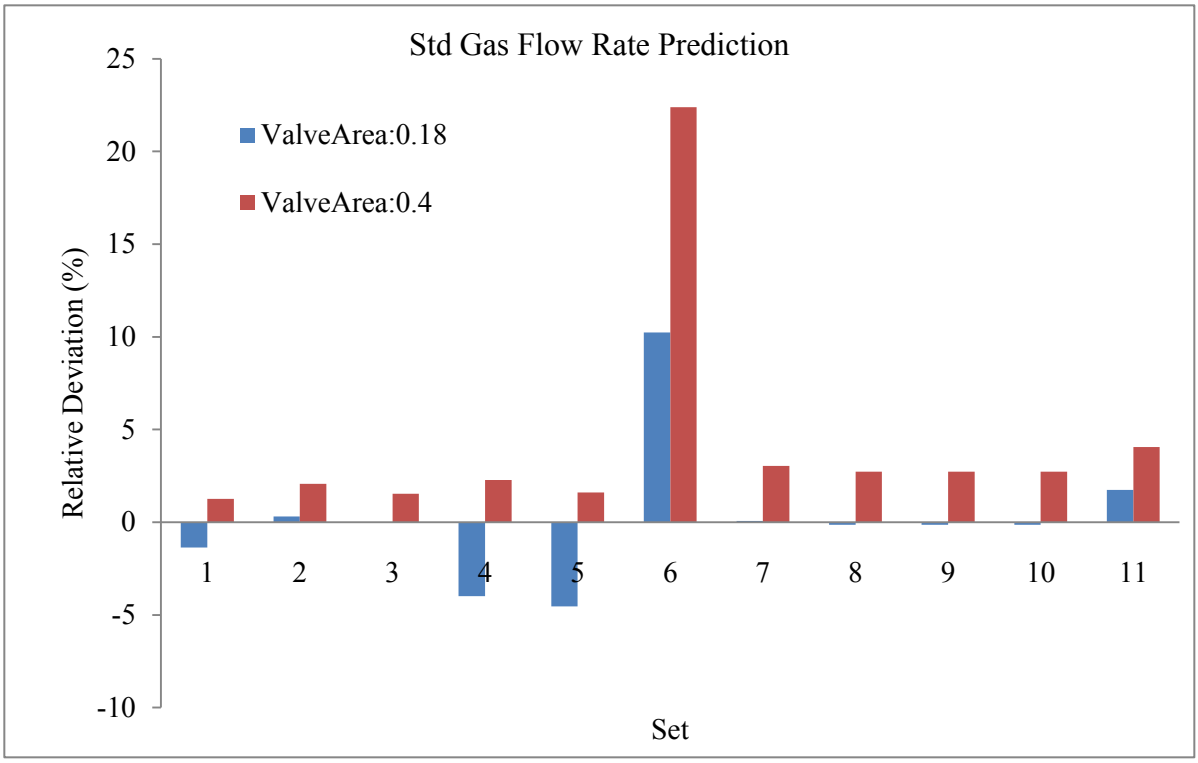

Figure 53. Gas Flow Rate Prediction, Company A

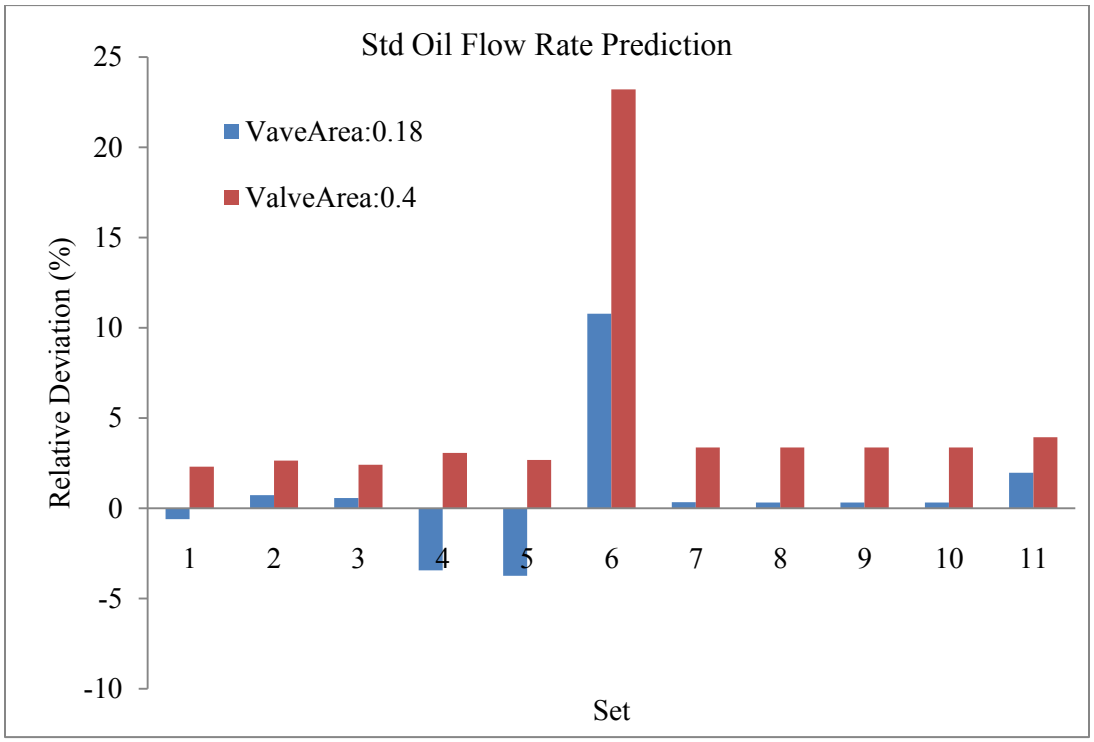

Figure 54. Oil Flow Rate Prediction, Company A

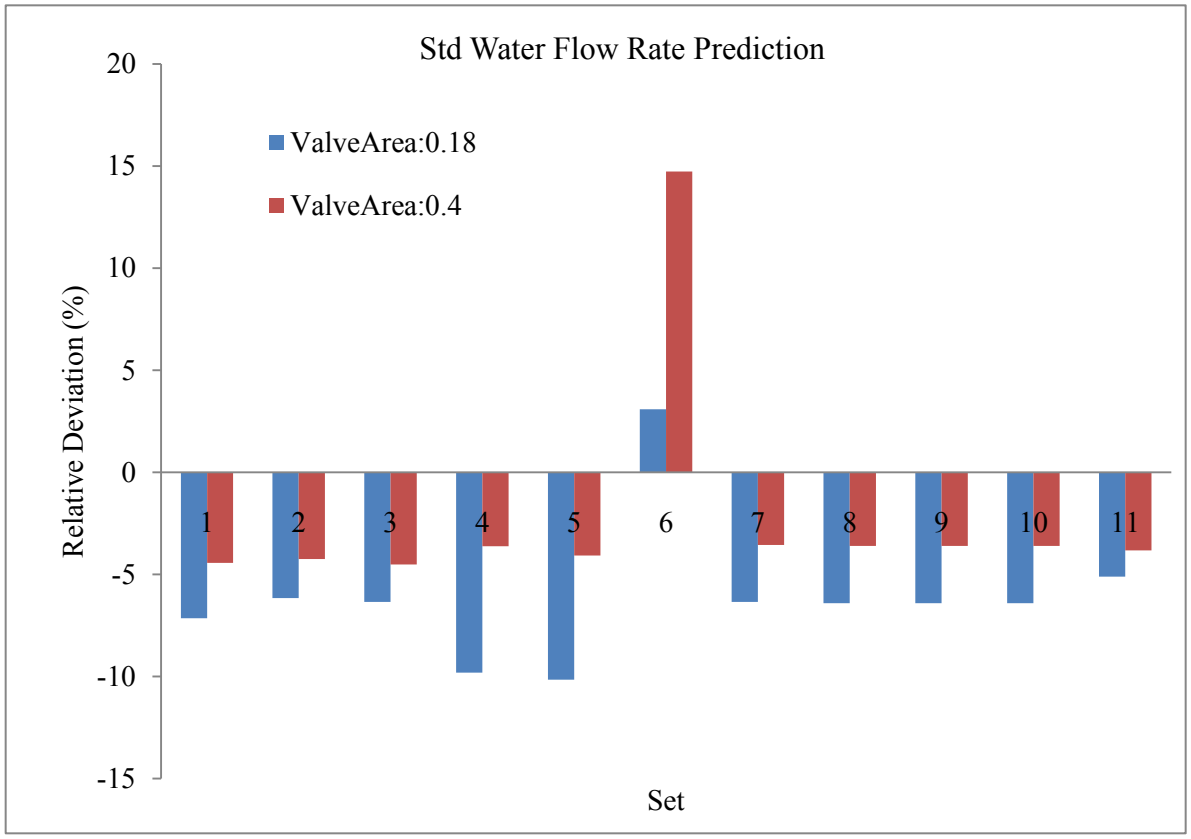

Figure 55. Water Flow Rate Prediction, Company A

Appendix D: Survey Results

The Online Survey Results may be found at:

http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=732

RPSEA

Meter Alteration Effects from Fouling and Erosion

07121-1301-Task5.FINAL

Improvements to Deepwater Subsea Measurement

07121-1301

August 29, 2011

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Flow Measurement Specialist
Letton–Hall Group
14511 Old Katy Road, Suite 362
Houston Texas 77079

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ABSTRACT

Multiphase/wet gas flow meters used in deepwater subsea conditions are known to have problems with scaling and erosion. The objective of this RPSEA project is to evaluate the flow meter performance changes produced by these meter altering mechanisms.

Multiphase/wet gas meter elements: Venturi, cone and wedge meters, were physically tested and subjected to Computational Fluid Dynamics (CFD) simulations.

The erosion testing was done with water-sand and air-sand on one size and one beta ratio of each meter type. CFD simulations were used to extend the size range, the beta range and the fluid densities to cover the multiphase density range between air and water.

Erosion results are presented that allows the user to estimate the possibility or likelihood of wall penetration, the measurement error and the effect of a flow meter on the erosion of a downstream bend.

The scale deposition testing was done with brine of mostly sodium and calcium on one size and one beta ratio of each meter type. No attempt was made to use either multiphase flow or realistic subsea conditions.

Scale deposition is a highly complex and variable process that is difficult to model. For CFD to be able to estimate meter error it would have to predict the distribution and thickness of scale in the meter. At present this is beyond the capability of CFD. However, CFD simulations were run to assess how meters are affected by scales that are sensitive to fluid scouring, pressure distribution, particle accretion and thermal effects.

These CFD-based methods are sufficiently realistic to provide an insight into the effects of scale. They are used to compare different meter designs and hence identify design features that may be desirable if scale formation is a concern.

Prepared by:	Approved by:
Klaus Zanker, (LHG)	8/29/2011 Date:

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1. Introduction

This project addresses gaps in the deployment and use of multiphase and wet gas meter technology in deepwater production systems. In particular the objective of this task is to understand the ways in which production alteration of meters affects their response.

It is known from field operations that meters can become fouled internally by deposits of scale, wax, asphaltenes, and hydrates, or altered by corrosion and erosion. At present these effects are not well understood and an objective is to estimate their magnitude.

Flow tests and computational fluid dynamic (CFD) analyses have been performed to evaluate the effects of alteration of some commonly used multiphase and wet gas meter elements, (e.g., Venturi, cone and wedge meters), by synthetic deposition (scale, wax, etc.) or by sand erosion. Measurements of the physical dimensions and flow through altered meters were made to characterize the effects of meter alteration on performance. The results are interpreted to give a clearer understanding of these meter alternation effects on sub-sea multi-phase meter response.

A deeper understanding of flow meter alteration effects will improve the industry's ability to recognize measurement issues, to make corrections, to improve production allocation, and to assess royalties to the BOEMRE (formerly the MMS). It will also help provide better information on well performance and improve recovery from deepwater reservoirs.

2. Organization

- Industry Champion: Gordon Stobie – ConocoPhillips. In this role, Mr. Stobie served as the lead technical interface between the JIP members, task manager and subcontractors.
- Task Manager: Klaus J. Zanker – Letton-Hall-Group. Mr. Zanker was the overall manager of the effort.
- Task Working Group. JIP members who have special interest in the Task technology or application: BHP Billiton, BP, ConocoPhillips, Chevron, Shell, StatoilHydro and Total
- Sub-contractors:
    - Southwest Research Institute (SwRI) for water/sand erosion testing
    - Tulsa University for air/sand erosion testing
    - Intertek for scale deposition testing
    - TUVNEL for CFD on erosion and scale

3. Details of Task 5 Plan

3.1 The Original Scope of Work

Method

As proposed, this was to be an experimental program to investigate the effects of fouling and erosion on meter performance. Meter body internals would be altered synthetically to mimic the real-world environment. Then the synthetically altered meters would be tested in flow loops to investigate the performance change.

Design

Two types of flow meters, Venturi and cone meter, were proposed with two diameters and two beta ratios for a total of 8 meters. Three types of alteration were proposed: , scale deposition, wax deposition and erosion by sand. Finally, wet gas and multiphase flow conditions were to be simulated.

Procedure

The original plan was to calibrate and take physical measurements and photographs of the meters in their "as new" condition. The meters would then be subjected to the alteration mechanism and measurements would be made of any physical changes to the meter's size, shape, surface finish and local tapping effects. A photographic record of the altered meters would be made. Finally, the meters would be calibrated in their altered state to quantify any change in performance.

The plan was to evaluate the first round of meter sensitivity tests to identify the most interesting conditions and then repeat the measurements of physical properties and flow through the altered meters to validate the initial test data.

Analysis

After collecting the experimental data, the analysis phase of the project included:

- Correlating the flow meter performance change with the physical changes
- Establishing the relative sensitivity of different meters to different alteration mechanisms and
- Creating mathematical models or correlations to simulate meter performance in the presence of alteration.

3.2 The Revised Scope of Work

The first JIP meeting at the start of the project agreed that scale deposition was the major problem, followed by erosion. The JIP members felt that hydrate, wax and asphaltenes were not a deep subsea problem due to the high temperatures associated with the flow meter's location. This reduced the testing to just scale and erosion, leaving spare capacity (by eliminating wax) that could be used to add a wedge meter to the Venturi and cone meter multiphase meter elements. The ISA Dual-Stream multiphase flow meter uses a Venturi and a wedge meter in series for wet gas measurement and is quite common in the Gulf of Mexico.

ConocoPhillips generously offered to provide some results on water/sand erosion of Venturi meters performed at SwRI. This allowed the JIP to consider CFD analysis as an addition to the experimental work, because the computational results could be verified against these SwRI experimental test results.

The JIP members expressed interest in water/sand and air/sand erosion testing to simulate the extremes of multiphase and wet gas applications. The members ruled out the experimental use of multiphase flow and HP/HT conditions as too complex.

The scale deposition tests were performed with brine, simulating the produced water, and not with a multiphase fluid flow. The scale deposition tests proved to be more difficult and time consuming than was expected. Thus CFD was utilized for further work.

The ConocoPhillips gift of the SwRI erosion work saved the JIP $46,000.

The original budget for buying meters of different size and beta ratio was $60,000. Only $20,000 was spent on physical flow meters by using CFD to change meter size and beta ratio, achieving another saving of $40,000.

A 2-in cone meter costs $2,500 to buy and $15,000 to test. We obtained a cost quotation of $8,500 to buy a 4-in cone meter and $60,000 to test it. The application of CFD, which was not originally considered, saves money, allows more variables to be considered and helps with modeling.

3.3 Project Deliverables

The JIP agreed on the following deliverables for this project:

1. Experimental and CFD results for three commonly used multiphase and wet gas meter elements (Venturi, cone and wedge meters) altered by synthetic deposition and erosion.

The meter's response before and after alteration should be captured for different meter designs and degrees of alteration.

2. An interpretation of the results to give a clearer understanding of these effects on meter response.
3. Models created to predict the effects of meter fouling on meter performance
4. A final report documenting the experimental results and interpretations, together with recommendations for further work.

4. Execution of Plan

4.1 Experimental and Computational Work Performed

The CFD erosion analysis took place from April to Aug 2009 at TUVNEL. It compared the CFD results to the Venturi water/sand erosion test results first, and then used CFD analysis to predict the cone meter erosion effects.

The experimental scale deposition work was performed from Aug 2009 to March 2010 at Intertek. The experimental tests used brine to deposit scale on the 2-in diameter stainless steel Venturi, cone and wedge meters.

The experimental water/sand erosion work took place from Feb to May 2010 at SwRI. The 2-in stainless steel Venturi, cone and wedge meters were eroded with the Venturi and wedge installed in series to model the ISA Dual Stream wet gas flow meter.

The experimental air/sand erosion tests were performed from March to July 2010 at the University of Tulsa. The 2-in stainless steel Venturi, cone and wedge meters were eroded with the Venturi and wedge installed in series to model the ISA Dual Stream wet gas meter.

The CFD analysis of scale deposition took place from March to Oct 2010 at NEL. This work compared the CFD analysis results to the Venturi, cone and wedge meter scale deposition tests at Intertek. The research effort also developed other ways of modeling scale deposition effects.

The CFD analysis of erosion was performed from May to Nov 2010 at NEL, This work compared the SwRI water/sand erosion test results and the Tulsa air/sand erosion test results with the CFD analysis results. The meter size and beta ratio were also varied by using CFD to help modeling.

A paper was presented to ThAW, in May, 2010 on erosion testing and CFD analysis of erosion effects as part of technology transfer. Another ThAW paper on erosion was presented in April, 2011 and a paper has been accepted for NSFMW in October, 2011.

4.2 Meters Tested

Figures 1-3 document the Venturi, cone, and wedge meters used for this task.

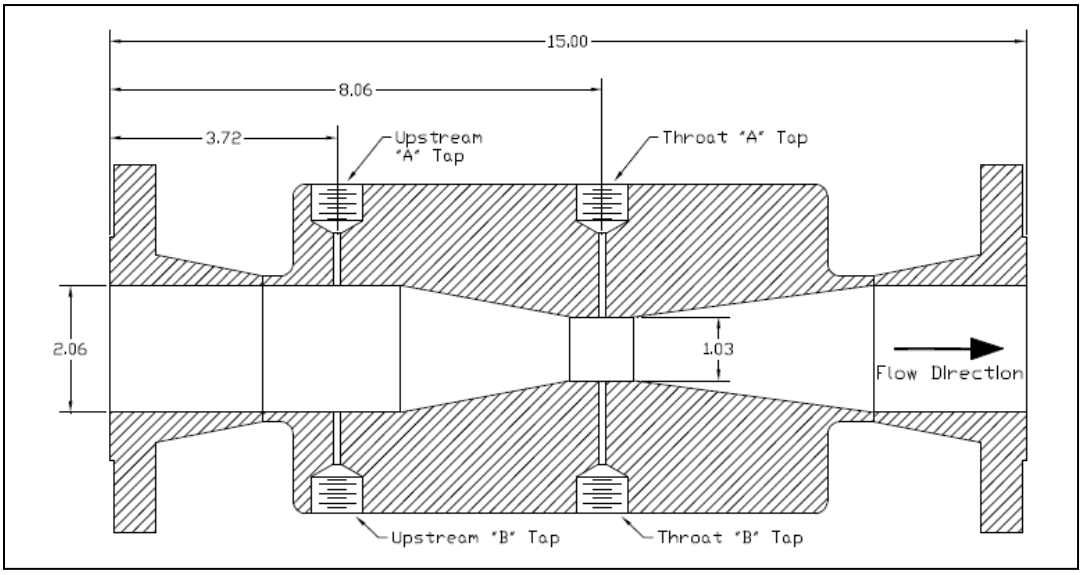

Figure 1. Cross-section view of the Venturi meter

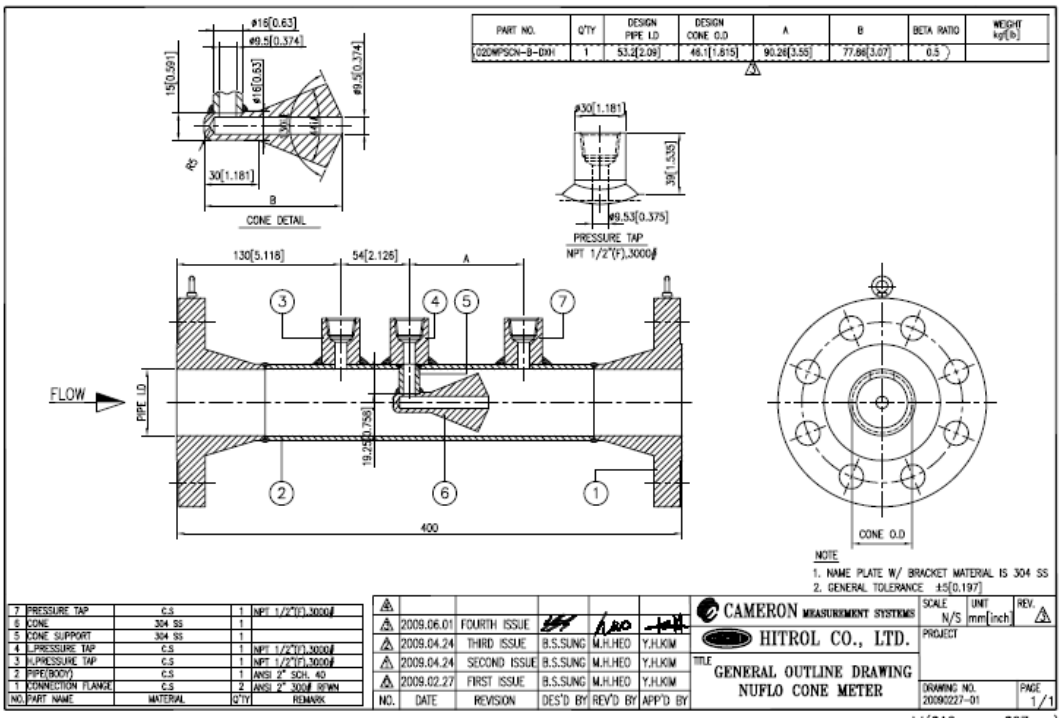

Figure 2. Cross-section view of the cone meter

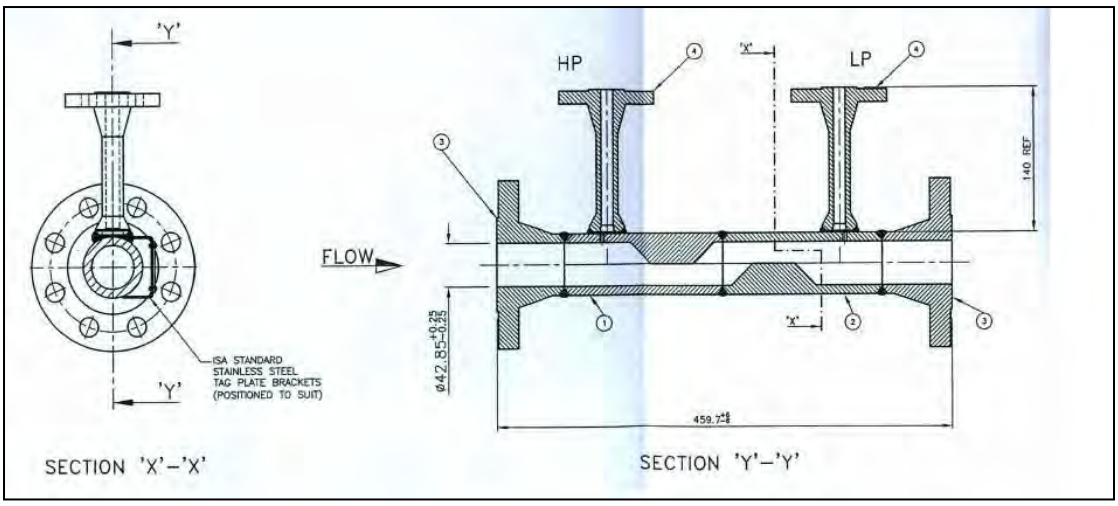

Figure 3. Cross-section view of the wedge meter

Table 1. Flow meter specifications

Flow Meter	Test Venturi	Wedge	Cone	"Standard" Venturi
Manufacturer	Fluidic Technologies	Solartron ISA	Nuflo	Fluidic Technologies
Serial No.	V-2707-1	44905	450207439-2	V-2586-1B
Pipe I.D.	2.067	1.689	2.1264	2.067
Beta Ratio	0.5	0.707	0.5	0.5
Cone O.D.	N/A	N/A	1.8413	N/A
End Connections	2" CL 300 RF Flanges – CS	2" CL 300 RF Flanges – SS	2" CL 300 RF Flanges – SS	2" CL 150 RF Flanges - SS

All meters were 2-in diameter, but the wedge meter was rated schedule 160, while the Venturi and cone meter were both schedule 40. Schedule 160 was the only rating option for the wedge meter.

These were the meters used in the experimental tests: with only one pipe size and one beta value. Several of the meters were tested under different conditions: scale deposition, water/sand erosion and air/sand erosion. The influence of different pipe sizes and beta ratio values were analyzed with CFD, resulting in substantial savings compared to buying and testing additional meters.

5. Erosion Results

5.1 Venturi erosion results given to the JIP by ConocoPhillips

The full report may be found at:

http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=607

The meters used were 2-in, beta = 0.5 stainless steel classical Venturi meters. They had two sets of pressure taps located upstream and in the throat (designated "A" and "B"). Three meters were used for erosion testing in the test rig.

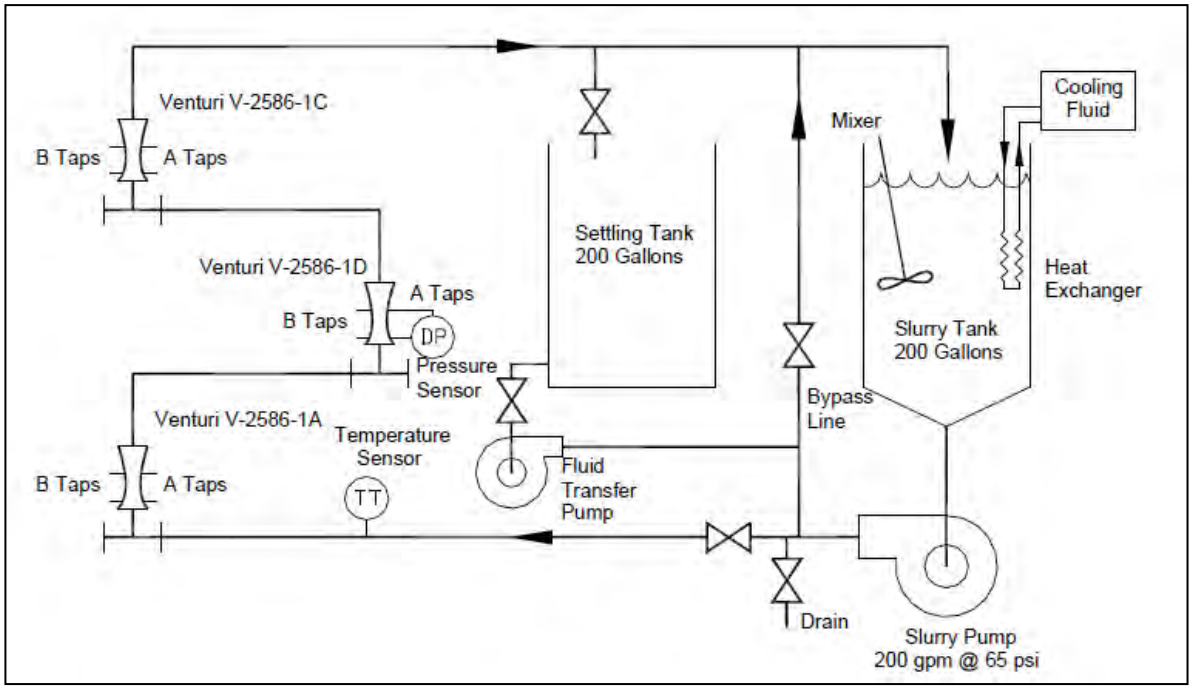

Figure 4. Schematic view of SwRI sand/water erosion test facility

A fourth meter, not exposed to erosion, was used as a reference in a calibration test rig. The discharge coefficient (C_d) was taken to be 0.995 from the standard.

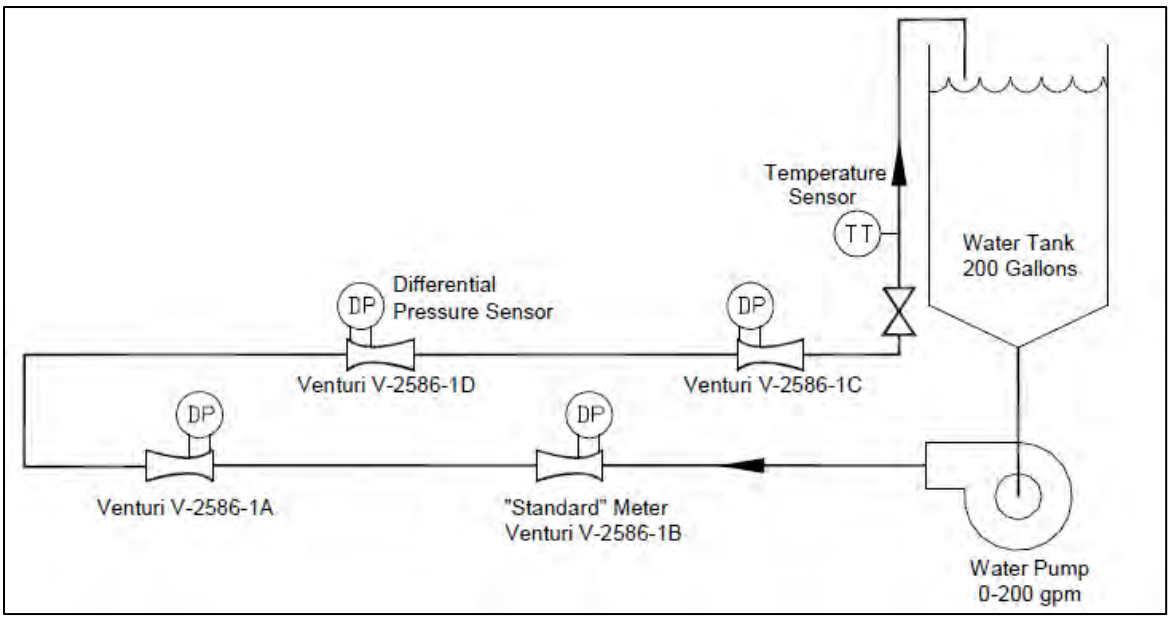

Figure 5. Schematic view of SwRI water flow meter calibration facility

Meters were calibrated flowing water in this rig before and after being exposed to erosion to determine the change in C_d.

Meter dimensions and photographs were taken before and after erosion to document the physical changes that occurred and to relate them to the changes in C_d.

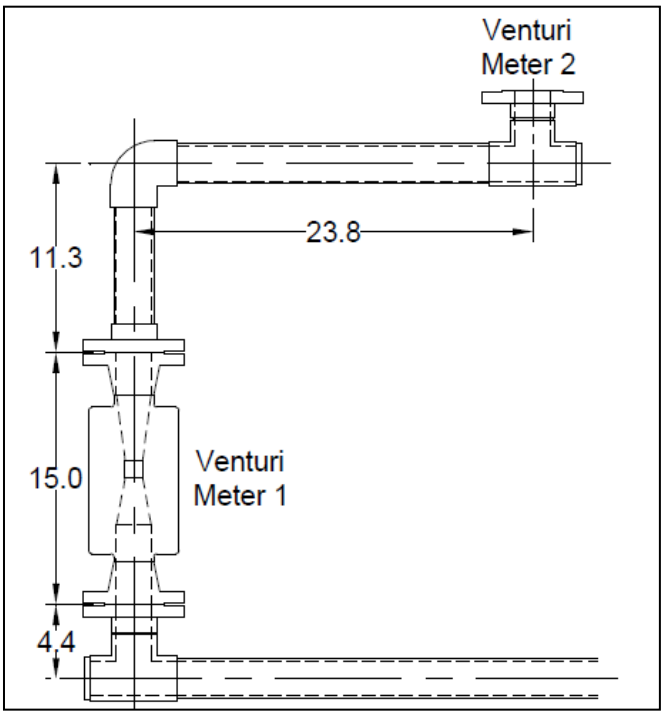

Figure 6. Venturi meter installed for upwards vertical flow

For the erosion tests the meters were installed with vertical upward flow and a blind "Tee" on the inlet to simulate a typical subsea multiphase meter installation. The blind "Tee" is considered to act as an effective mixer with multiphase flow.

Sand Used in the Tests

The sand used in the tests was AGSCO Corporation Quartz #1 sand. The mean sand grain diameter was 276 microns, with a range from about 125 microns to about 600 microns.

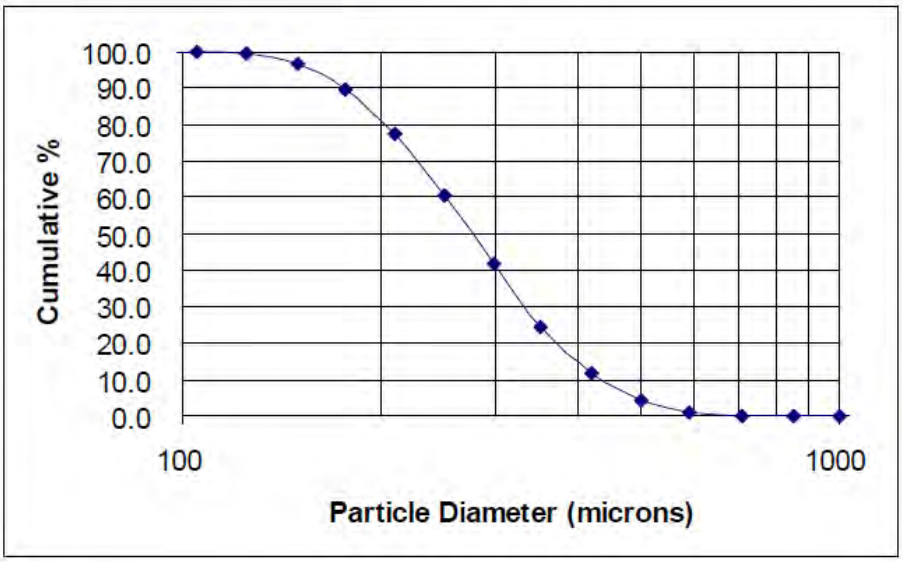

Figure 7. Particle size distribution for sand used in erosion tests

A photograph of the sand used in the tests is shown below:

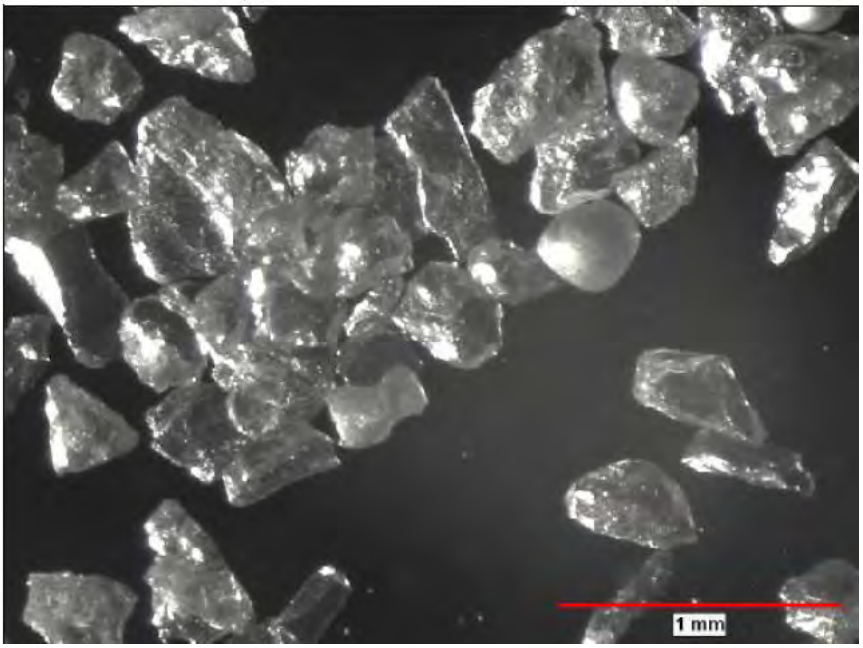

Figure 8. Photograph of sand particles

Table 2. Summary of the water/sand erosion test conditions

Condition	Value
Run Time (hr)	242
Average Sand Concentration (% by wt)	4.57
Average Temperature (°F)	77.5
Average Venturi DP (psi)	13.075
Fluid Viscosity (cP)	0.884
Fluid Density (g/cc)	0.997
Throat Reynolds No.	419900
Average Sand Concentration (% by vol)	1.77
Sand/Water Mixture Density (g/cc)	1.026
Average Venturi Flow (gpm)	116.8
Venturi Throat Velocity (ft/sec)	44.7
Venturi Inlet Velocity (ft/sec)	11.2
Mass of Water Through Venturis (lbm)	14,532,000
Mass of Sand Through Venturis (lbm)	664,000

Note that the sand concentration is much higher than anything expected in the field. This is done to produce erosion in a much shorter time than several years in the field.

Venturi Meter Discharge Coefficient Measurements

Table 3. Discharge coefficient measurements made before and after Venturi meter exposure to water/sand slurry flow – "B" meter taps.

	Venturi V-2586-1A	Venturi V-2586-1D	Venturi V-2586-1C
Average Cd Value Before Erosion Test	0.9963	0.9947	0.9967
Average Cd, After Water Erosion Test	0.9871	0.9825	0.9846
Change in Cd (%)	-0.92	-1.23	-1.21

Table 4. Discharge coefficient measurements made before and after Venturi meter exposure to water/sand slurry flow – "A" meter taps.

	Venturi V-2586-1A	Venturi V-2586-1D	Venturi V-2586-1C
Average Cd Value Before Erosion Test	0.9993	0.9942	0.9947
Average Cd, After Water Erosion Test	0.9847	0.9856	0.9869
Change in Cd (%)	-1.46	-0.86	-0.79

The average effect of the erosion on six meters (3 meters X 2 taps) is to reduce C_d by about 1%.

Venturi Meter Dimensional Changes due to Erosion

The inside diameter at the upstream pressure tap was increased by 0.001". The inside diameter at the throat tap was increased by 0.005". The throat bore became tapered with a larger diameter downstream. The meter was polished, by removing machining marks, with the surface roughness reduced from about 35 micro-inches to 16 micro-inches.

The most striking change was erosion of the throat tap. The eroded portion of the throat taps was on the downstream side of the tap hole.

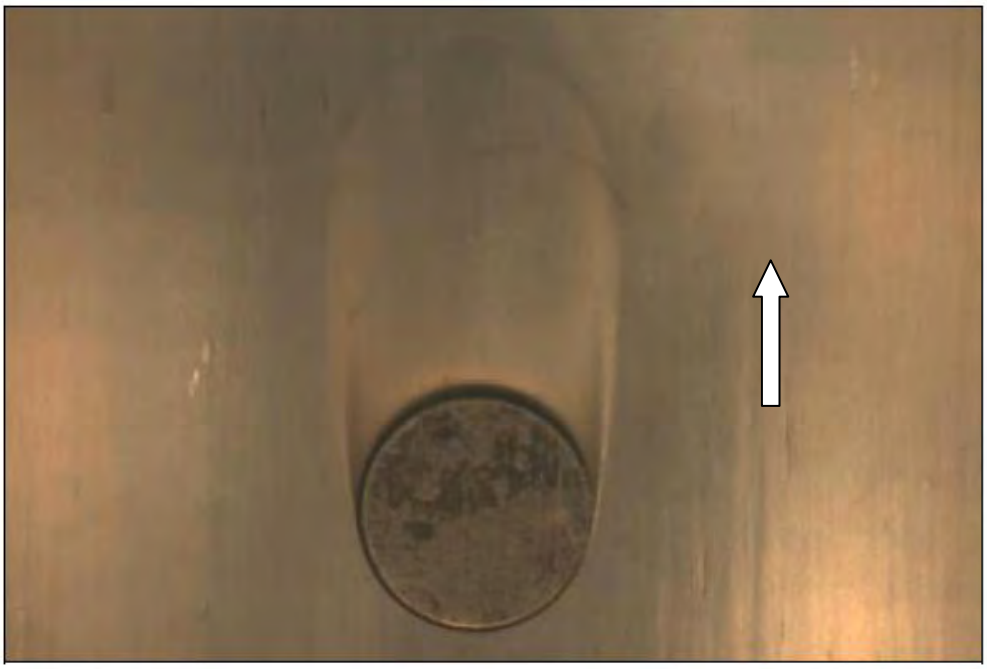

Figure 9. Photograph of throat tap after erosion.

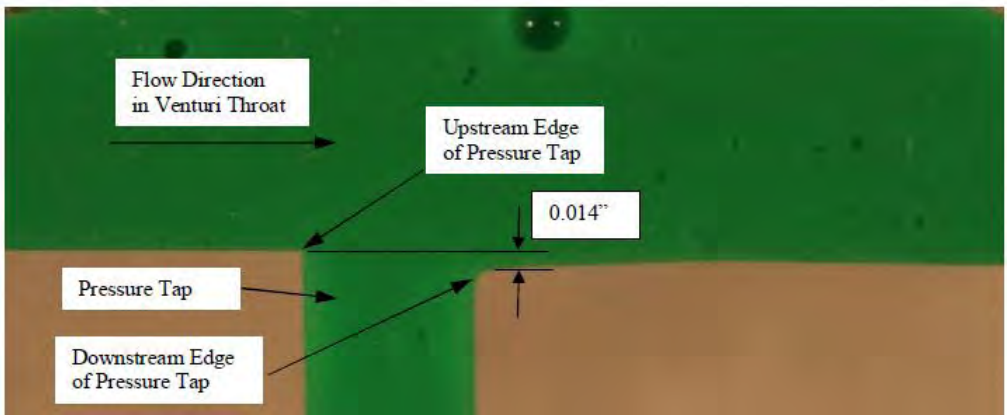

Figure 10. Photograph of a cross-sectional slice cut from a casting of the throat tap

Venturi Meter C_d and Dimensional Changes due to Erosion

The increase in throat bore diameter would reduce the DP (differential Pressure) and increase C_d, as $q = C_d*a*E*\sqrt{DP/\rho}$. The erosion at the throat tap would reduce the pressure at the tap, increasing the DP and reducing C_d.

The 0.5% increase in throat diameter results in a 1% increase in area and a 1% reduction in velocity (V), a 2% reduction in $V^2/2g$ or DP, and a 1% increase in C_d. Since the measured effect was a 1% decrease in C_d, this suggests that the throat tap erosion has reduced C_d by 2% to get the net experimental result.

5.2 CFD Erosion Analysis of a Venturi

This work, undertaken by TUVNEL Ltd, used Computational Fluid Dynamics (CFD) simulations to assess the sand erosion effects in flow meters. Simulations were run using ANSYS FLUENT 6.3.26 CFD computer software. The full report may be found at:

http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=610

The first CFD simulation was for a 2-inch Venturi meter in water-sand flow, as tested by SwRI. One group of simulations was run to calculate the erosion distribution within a meter and a separate second group of simulations was performed to calculate the flow measurement error caused by the surface damage.

First a CFD simulation of the flow of clean water through the flowmeter was performed. Water density and viscosity were set to be 1000 kg/m^3 and 1 cP respectively and the inlet velocity was set to 3.413m/s (11.2 ft/s as in the SwRI test). Turbulence effects were represented by the realizable k-epsilon turbulence model.

A large number of small, spherical particles, representing sand, were then injected at the inlet. The particle density was set to 2650 kg/m^3 and the size distribution was set to match that in the SwRI tests, with a mean particle diameter of 276 microns.

Whenever a particle impinged on the pipe wall, the impact velocity and angle were used in the following equation, based on work performed by Haugen et al[1], to calculate the local erosion rate:

$$\dot{E} = C_{unit} \dot{m}_P K U_P^n F(\alpha) \qquad \text{Equation 1}$$

In which:

$\dot{E}$ is the erosion rate (mm/kg of sand passing through the pipe work)

C_{unit} is a factor to convert the erosion rate to mm/kg

$\dot{m}_p$ is the mass flow rate of sand impacting the region in question (kg/s)

U_P is the particle impact velocity (m/s)

α is the impact angle

F(α) is a function that accounts for the variation of erosion caused by differing impact angles.

Coefficients K and n were set to represent a "steel grade" material. The erosion rates of different materials depend upon the material hardness. In practice most steels (including carbon steel, 316 stainless steel, and duplex stainless steel), Stellite and Inconel show a similar erosion resistance.

Particle bounce characteristics were calculated using a model described by Forder et al[2].

When the transporting fluid is turbulent, particles travelling with the fluid are buffeted by random turbulent eddies. Small, light particles and particles in highly turbulent liquid flows are particularly prone to this effect. In some cases, turbulence can act to move particles closer to the walls, thus increasing the chances of a wall impact. Alternatively, it may disperse a concentrated stream of particles, spreading impacts and causing a wide and shallow erosion scar compared to a deep and narrow scar. In ANSYS FLUENT, a stochastic, discrete random walk model applies random forces on the injected particles to account for turbulence effects.

In most single phase flow applications, scar depths are usually over-predicted but are within one order of magnitude of test results. Less accurate predictions would be expected in liquid-gas-sand mixtures, in low Reynolds number flows, and for particles smaller than 100 microns.

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[1] HAUGEN, K., KVERNVOLD, O., RONOLD, A. & SANDBERG, R. *Sand erosion of wear-resistant materials: erosion in choke valves.* Wear 186-187, pp 179-188, 1995

[2] FORDER, A., THEW, M.T. & HARRISON, D. A numerical investigation of solid particle erosion experienced within oilfield control valves. Wear, Vol 216, pp184 – 193, 1996

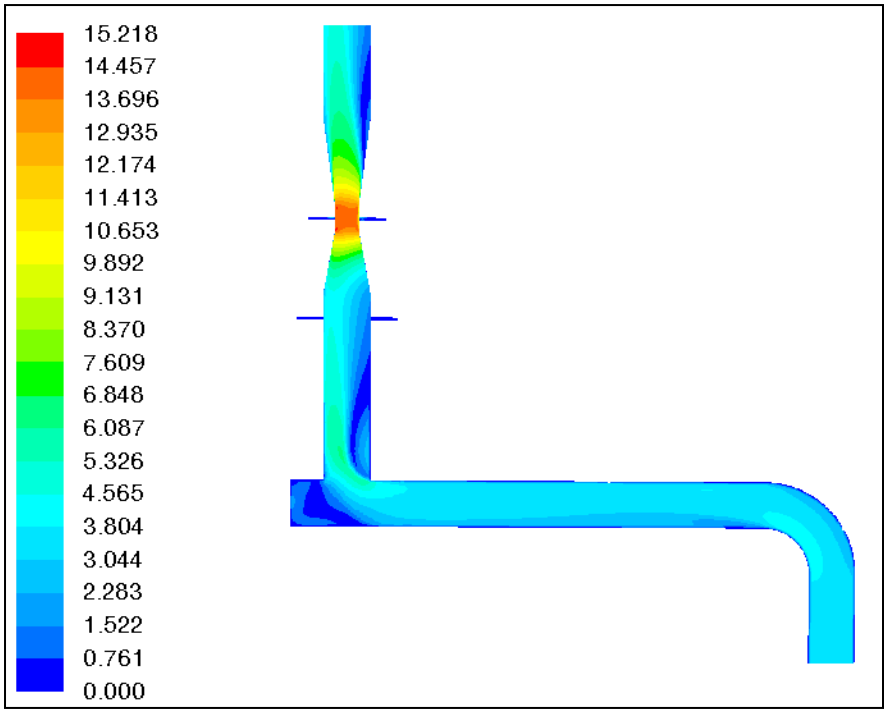


Figure 11. Contour map of liquid velocity (m/s) from CFD analysis

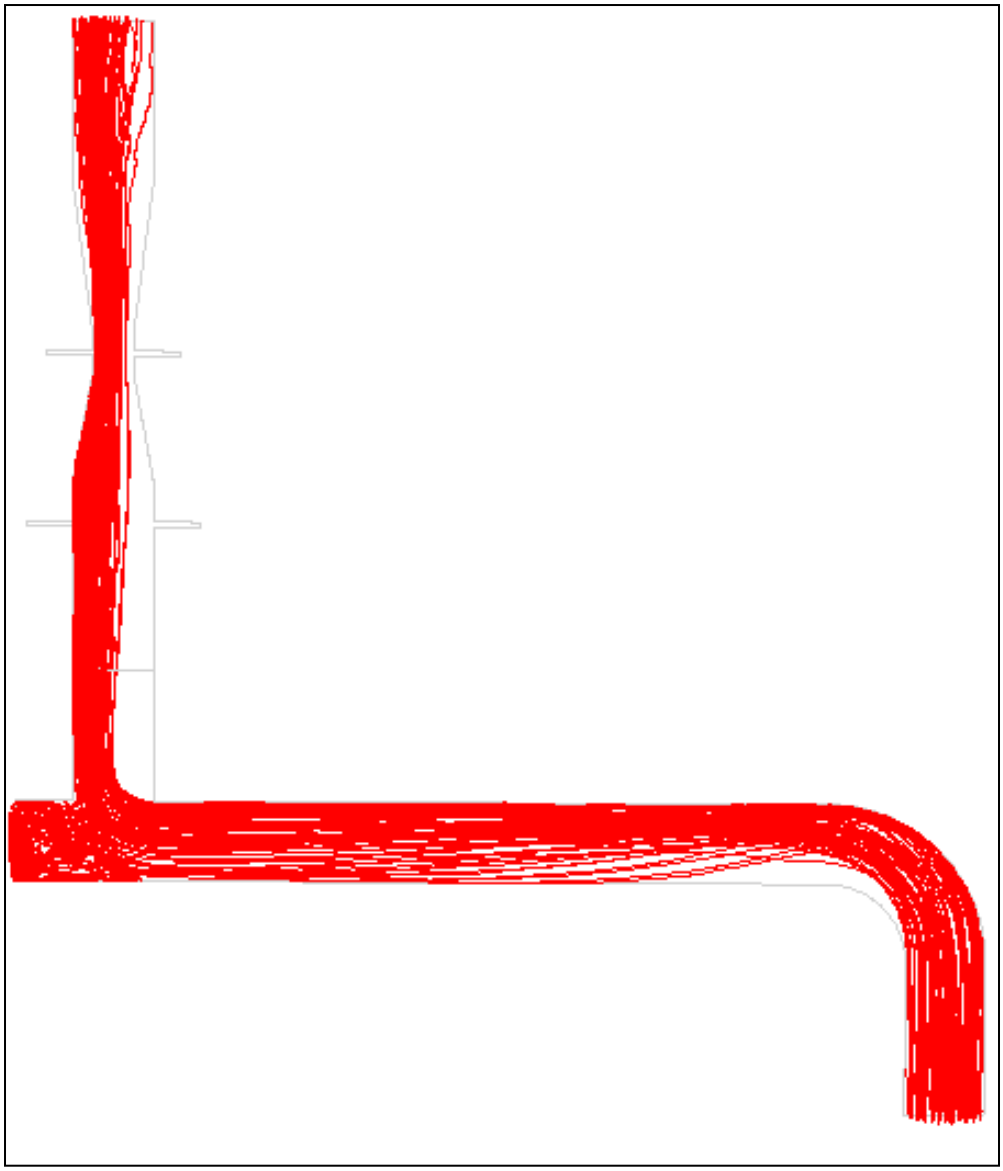


Figure 12. Particle Trajectories (650 micron particles) from CFD analysis

The blind "Tee" does not act as a mixer with the sand/water flow, but more like an inertial separator.

Figure 13 clearly shows the erosion in the convergent section, as was seen in the tests. However, a significant difference between the CFD predictions and the test results is that no erosion was predicted in the Venturi throat or throat tapings when using the default CFD model. A number of possible reasons for this discrepancy were investigated.

- Particle Bounce Effects
- Near Wall Turbulence Effects
- Particle Concentration Effects

These could account for the increased experimental erosion.

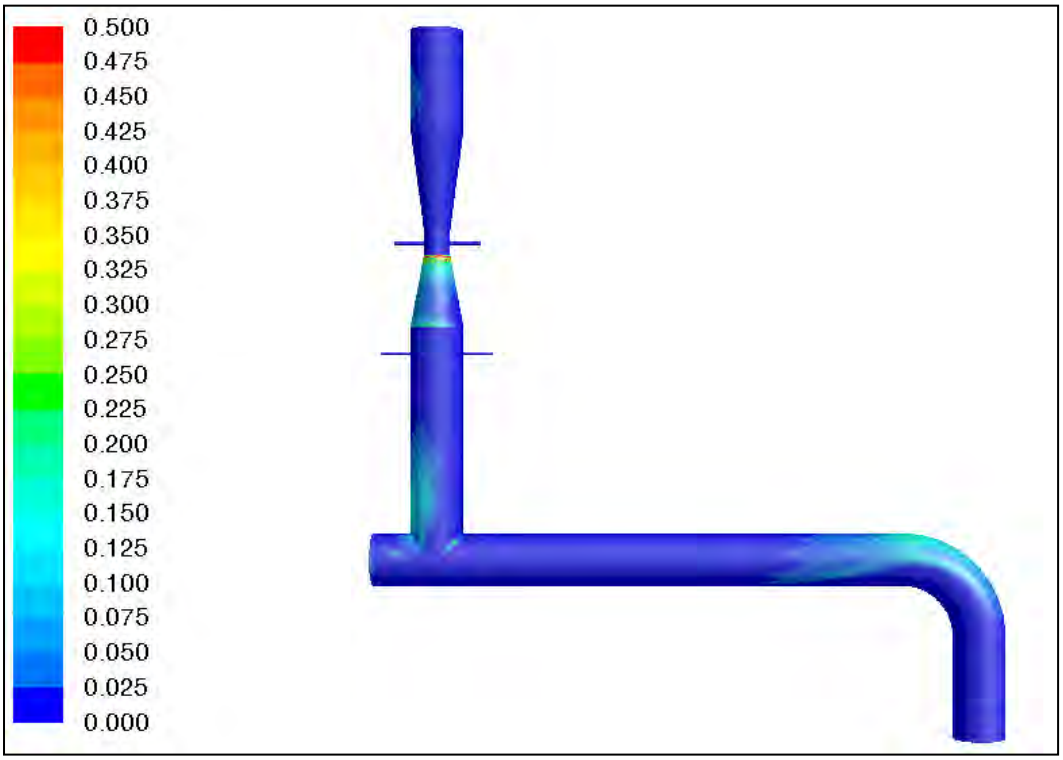


Figure 13. Predicted erosion depth contours for the Venturi (mm) from CFD analysis

5.3 CFD Measurement Error Simulations

The effects of erosion on flow meter accuracy were assessed in separate simulations, analogous to the water flow calibrations performed at SwRI. Clean water flow simulations were run without the tee and elbow and with fully developed flow defined at the inlet.

The first stage in calculating the shift in discharge coefficient entailed simulating a pristine meter to calculate a discharge coefficient:

$$C_{pristine} = \frac{q_{actual}\sqrt{1-\beta^4}}{\frac{\pi}{4}d^2\sqrt{2\Delta P\rho}}$$

Equation 2

Where

q_{actual} is the actual mass flow rate (as defined in the simulation set up) kg/m^3

β is the diameter ratio

d is the throat diameter (m)

ΔP is the pressure difference between the upstream and downstream taps (Pa)

ρ is the water density (kg/m^3)

ΔP was calculated based on the mean pressure at the base of the tapping holes, predicted by the CFD simulation.

A second simulation was then run with the wall manually distorted to approximate an erosion scar at a point of interest. The shift in discharge coefficient caused by the erosion scar was calculated thus:

$$C_{eroded} = \frac{q_{actual}\sqrt{1-\beta^4}}{\frac{\pi}{4}d^2\sqrt{2\Delta P\rho}}$$

Equation 3

$$\%\ shift\ in\ C = 100\frac{C_{eroded} - C_{pristine}}{C_{pristine}}\%$$

Equation 4

5.4 CFD Measurement Error Simulations of a Venturi

Table 5. CFD prediction of discharge coefficient shift caused by erosion

Run	Convergent	Throat	Tapping	C	% Shift in C
1	Pristine	Pristine	Pristine	0.986	0
2	Pristine	Pristine	Eroded	0.976	-1.00
3	Pristine	Eroded	Eroded	0.984	-0.18

Interestingly, the predicted error in run 2 (eroded taps and pristine throat) is within the scatter of the SwRI test data. When the throat profile is modified to mimic erosion (run 3) then the predicted shift in C is less than that observed in the tests.

The CFD analysis has difficulty predicting these small effects, but the total effect is only 1%.

5.5 CFD Erosion Analysis of a Cone meter

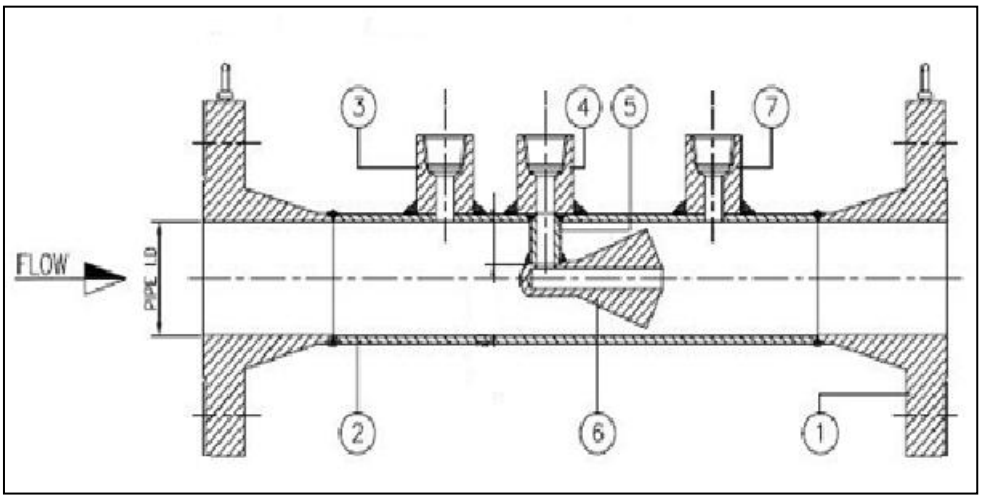


Figure 14. Cone meter geometry

In normal single phase flow, the cone meter uses upstream tap 3 & downstream tap 4 in the base of the cone 6. In horizontal wet gas flow, taps 3 & 4 can be used, but in wet gas vertical upward flow the base tap 4 would fill with liquid. To avoid this, wall tap 7 is used instead of the base tap. Both taps were included in the CFD analysis.

CFD simulations modeled a beta=0.5425 cone meter, which theoretically, should have the same differential pressure as a beta=0.5 Venturi meter operating under identical conditions. They should both have the same value of C*m*E (Discharge coefficient * Area ratio * Velocity of approach factor). The main difference is that for the Venturi meter C_d = 1 and for the cone meter C_d = 0.8.

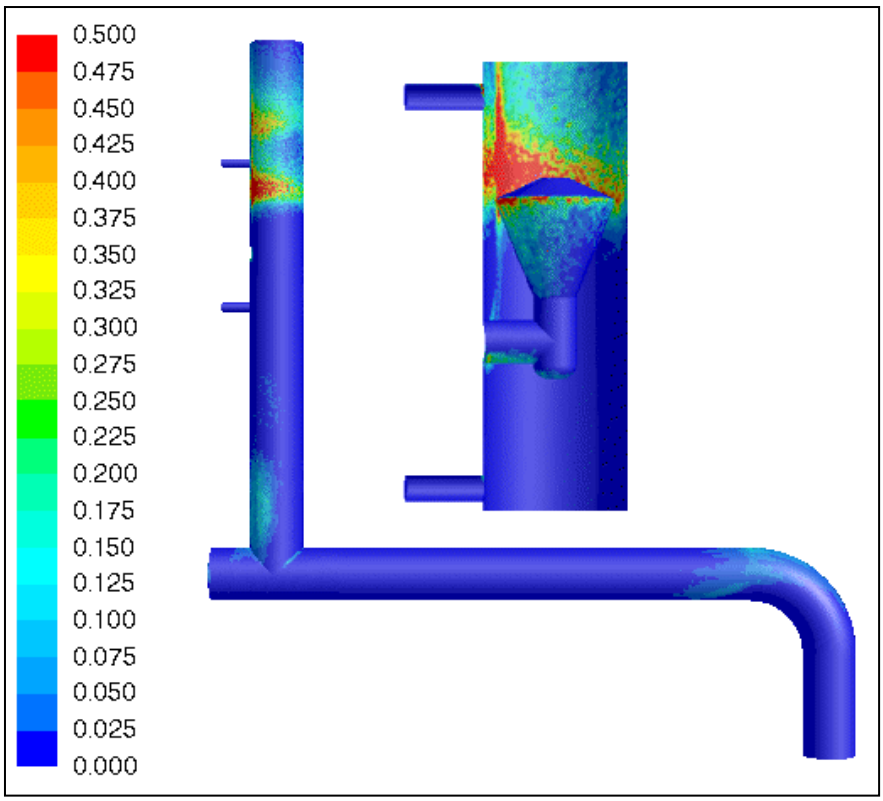


Figure 15. Cone meter – predicted erosion depth contours (mm) by CFD analysis

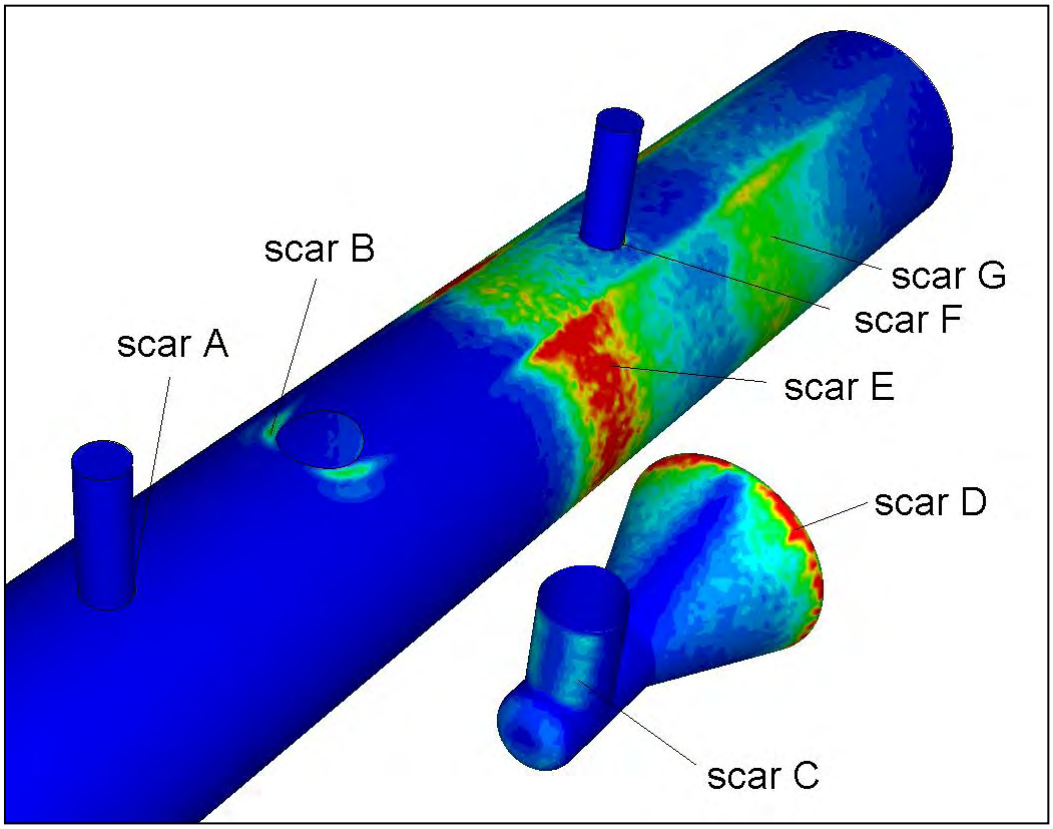


Figure 16. Predicted erosion scar depth for the cone meter (mm) from CFD analysis

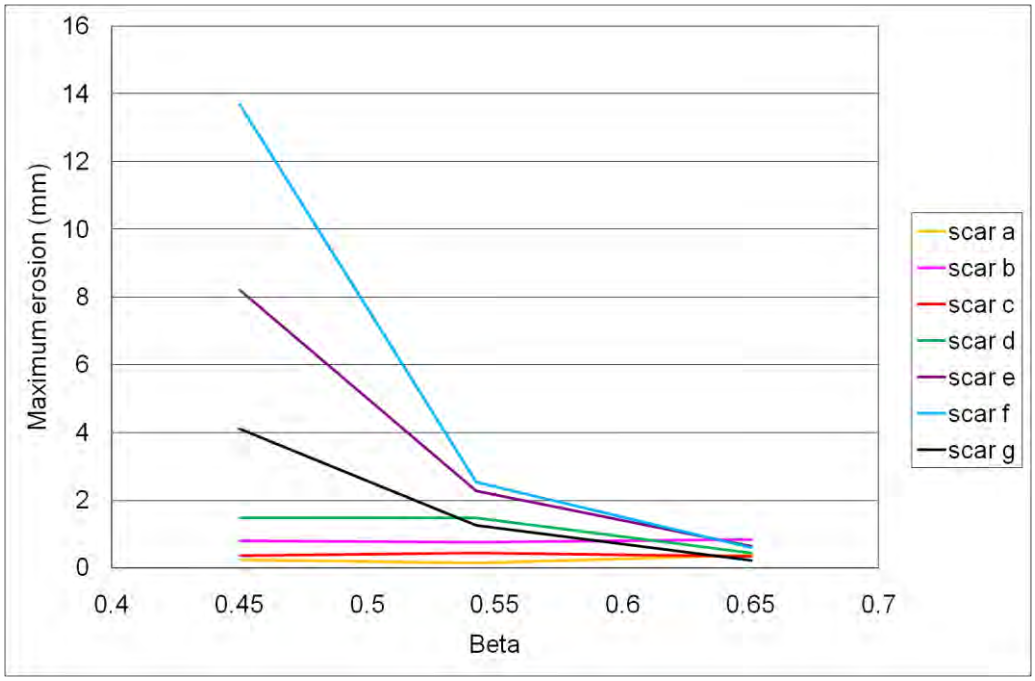


Figure 17. Variation in scar depths with beta ratio from CFD analysis

In a cone meter, erosion is primarily caused by particles that have previously been travelling near the pipe axis. Therefore, the influence of the pipe wall boundary layer on erosion in a cone meter will be small. Hence, the CFD predictions of erosion in a cone meter are believed to be more accurate than those for a Venturi meter.

5.6 CFD Measurement Error Simulations of a cone meter

The same scars are used to estimate the % change in C_d.

<u>Scars A (0.15 mm) and F (2.4 mm) – tapping edge scars</u>

The upstream tap F and the cone base tap have little erosion and negligible effect on C_d. The downstream wall tap has -0.9% effect on C_d.

<u>Scar B (0.6 mm) – pipe wall at the stem base</u>

Scar B was assumed to have no significant influence on the meter accuracy. In practice it could affect meter integrity.

<u>Scar C (0.4 mm) – stem and cone nose</u>

Maximum predicted erosion in this region was 0.4 mm and the scar depth was typically in the 0.1 to 0.3 mm range. The extensive erosion to the front of the cone has little effect on meter accuracy and was therefore ignored.

Scar D (1.2 mm) – cone diameter

The maximum erosion on the outer edge of the cone was predicted to be 1.2 mm and the average around the circumference was about 0.6 mm. The predicted erosion depth of 0.6 mm would cause a shift in discharge coefficient of about +30%. This is due to a reduction of the cone diameter and a rounding of the edge.

Summary

It has been shown that a cone meter operating in conditions identical to the SwRI water/sand tests is likely to suffer reduced accuracy much more quickly than the equivalent Venturi meter. Erosion of the maximum cone diameter is estimated to cause a shift in discharge coefficient of approximately +30%. Erosion of the wall downstream of the cone is estimated to cause a shift of about +8%. Other erosion scars have minor effects in comparison. Based on these CFD predictions, a shift in discharge coefficient of the order of +40% can be expected in the cone meter compared to measured values and predicted values of approximately -1% and less for an equivalent Venturi meter. Why is the predicted error for a cone meter so large? This is mostly a geometric problem: the Venturi throat is 26.5 mm diameter, while the gap between the cone and pipe wall is only 4 mm, making it much more sensitive to erosion in the fluid flow passage.

5.7 CFD Erosion in Sand-Gas Flows

Additional CFD erosion simulations were run for a Venturi and for a cone meter calculated for a gas-sand mixture. The mean gas velocity was set to 30 m/s, its density 50 kg/m^3 and viscosity 1.8 x 10^{-5} Pas to represent conditions typical of those upstream of the choke in a gas production system. Erosion rates were calculated for the same 664000 lb of sand as in the water flow tests. All other parameters were as defined for the water-sand simulations. The aim of this exercise was to assess whether the sand-water test and CFD simulation results were representative of all multiphase flow conditions including gas-sand mixtures.

In water-sand flow, the trajectory of small sand particles is largely dependent on the liquid flow direction. In gas-sand flow, particles ricochet within the meter and the cone tends to deflect particles onto the pipe walls. The primary erosion scars are similar for the water-sand and gas-sand simulation cases. However, scar E, on the pipe wall, is particularly deep in the sand-gas case. This implies that the cone meter in gas-sand flow is significantly more likely to suffer from pipe wall penetration than a similar Venturi in gas-sand flow.

Sand Figures 18 and 19 shows the particle trajectories in a Venturi and a cone meter in water-sand and gas-sand flow predicted from CFD analysis. The trajectories are colored by particle size measured in meters.

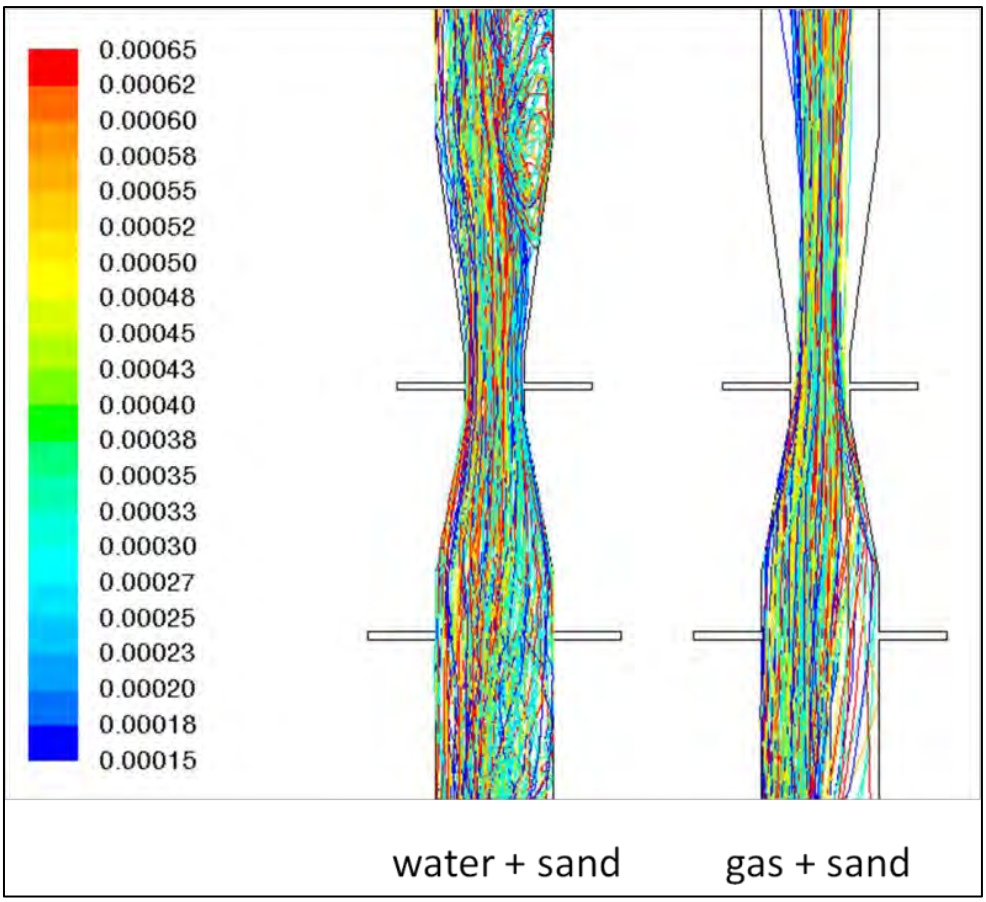


Figure 18. particle trajectories for a Venturi meter from CFD analysis

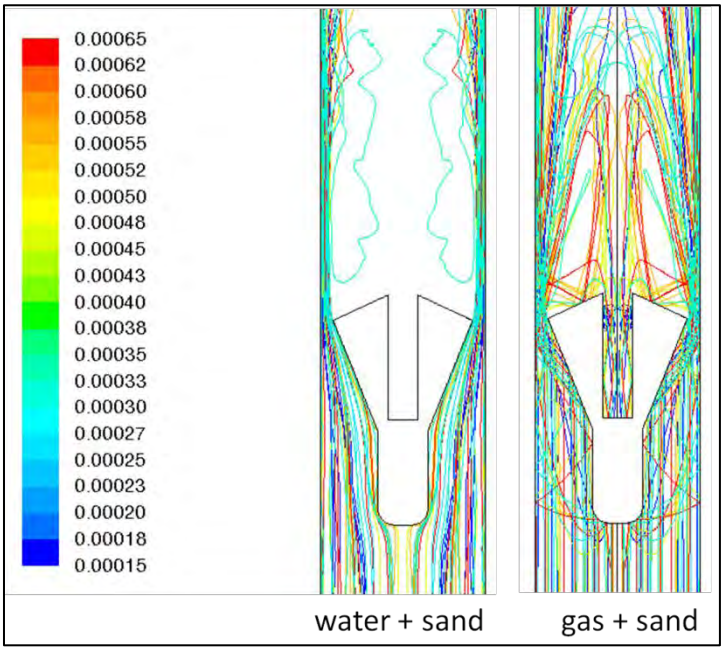


Figure 19. Sand particle trajectories for a cone meter from CFD analysis

In gas-sand flow, very high erosion rates are predicted at the pipe wall downstream of the cone. Cone edge erosion is likely to be high and the meter accuracy will suffer in consequence. In a Venturi, erosion in the throat is less likely in gas-sand flows than in liquid-sand flows. Wall penetration is also less likely in a Venturi.

Comparison of these plots shows that the erosion rate in gas-sand flow is of the order of one thousand times higher than in water-sand flow, e.g., 1 kg of sand in gas flow could realistically cause a similar amount of damage to 1000 kg of sand in a liquid-sand flow. The main difference is the air velocity of 30 m/s and the water velocity of 3.4 m/s.

5.8 Flow Meter Water/Sand Erosion tests at SwRI

The full report may be found at:
http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=608

These tests were repeated for this JIP project. The tests are very similar to the SwRI Venturi only test results given to the JIP by COP. However, these tests included Venturi, cone and wedge meters. The flow test for change in C_d is the same, but for the erosion test the meters are horizontal (not vertical) and the Venturi is closely coupled to the wedge, to model the ISA Dual-Stream wet gas meter.

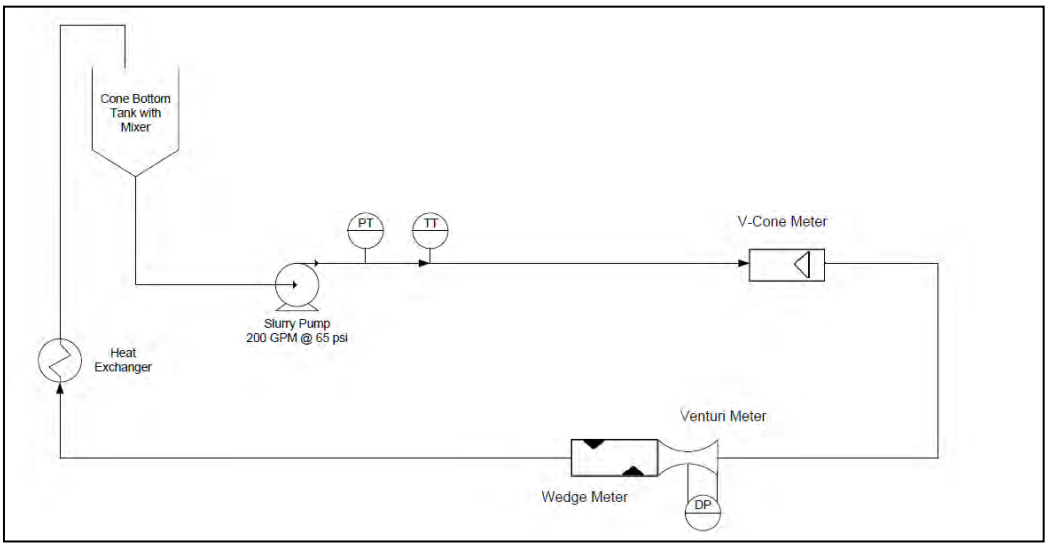


Figure 20. Schematic view of SwRI sand/water erosion test facility for simultaneous tests of a Venturi, cone and wedge meters

Table 6. Summary of the SwRI erosion test conditions

Condition	Value
Run Time (hr)	196
Average Sand Concentration (% by wt)	2.28
Average Temperature (°F)	80.4
Average Venturi DP (psi)	13.85
Sand/Water Mixture Density (g/cc)	1.012
Average Venturi Flow (gpm)	121.5
Mass of Sand Through Meters (lbm)	274,810

The idea was to run the same 664,000 lb through the meters, but when the wall of the wedge meter was breached due to erosion the test was stopped at 274,810 lb.

Table 7. Summary of results for simultaneous erosion tests of a Venturi, cone and wedge meter at SwRI

	Venturi	Cone	Wedge	units	Wedge
Beta	0.5	0.5	0.707		0.707
D	2.067	2.126	1.689	in	2.067
d	1.034	1.063	1.194	in	1.461
a = d^2	1.068	1.130	1.426	in^2	2.136
Cd	0.995	0.786	0.753		0.753
Cd * a	1.063	0.888	1.074	in^2	1.608
dP/120gpm	13.66	19.43	10.66	psi	4.75
Cd change	-0.63	10.77	1.72	%	
scar	0.001	0.14	0.343	in	

The wedge meter had the largest beta (0.707), the largest flow restriction area C_d*a (1.074) and the smallest dP (10.66 psi), yet it had the worst erosion scar (0.343 in) that breached the meter wall during the experiments.

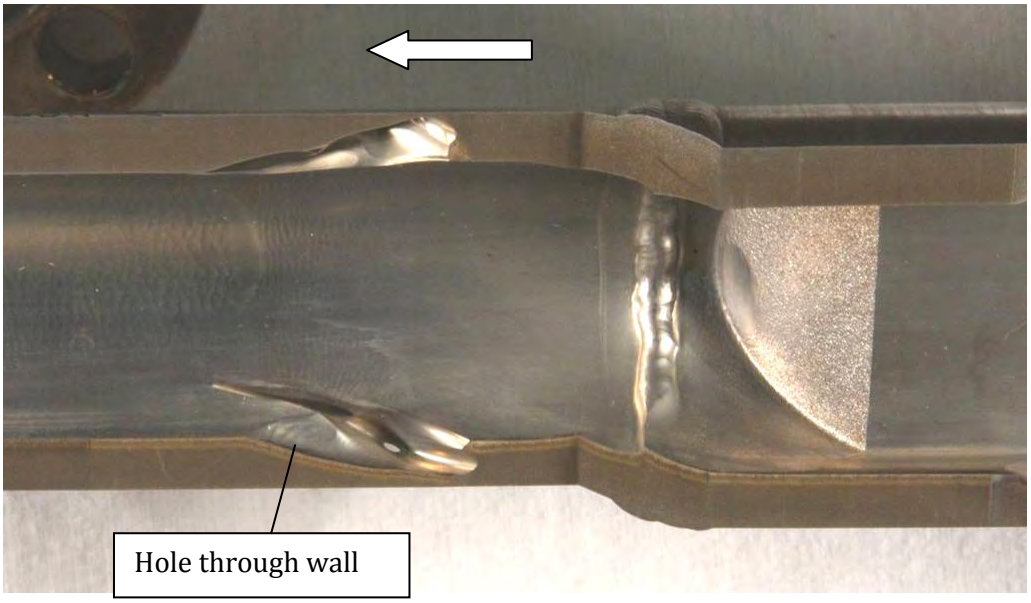


Figure 21 . Photograph of the wedge meter after sectioning showing the penetration of the meter tube wall caused by sand-water erosion.

The upstream ramp of the second wedge throws the sand directly at the wall, but does not do much other serious damage as the C_d only changes by 1.72%. The wedge meter is schedule 165 and not schedule 40. The last column of Table 7 shows that if the wedge meter had the same inside diameter as the other meters, the dP would drop to 4.75 psi or half its previous value, which would at least halve the erosion.

The cone meter has the largest dP and the largest change in C_d (10.77%), but not as severe erosion (0.14 in. scar). The design with the small annular gap between the cone and pipe diameters causes the problem.

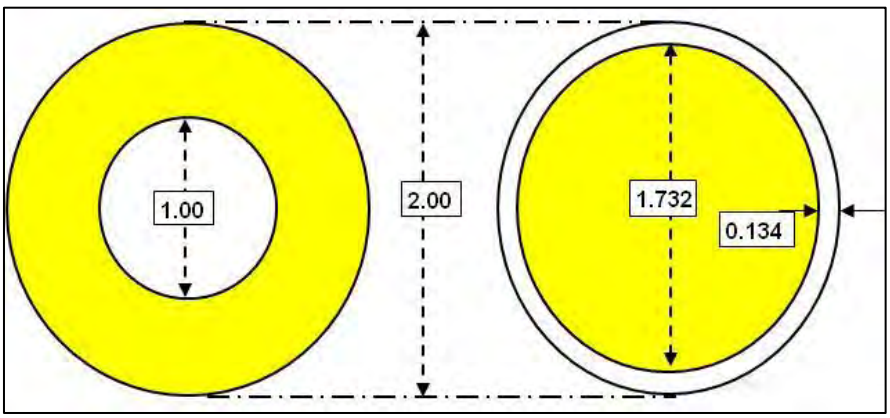


Figure 22. Comparison of a beta = 0.5 Venturi and a beta = 0.5 cone meter.

The flow areas are the same, but the gap between cone and wall is only 0.134 inches in the cone meter.

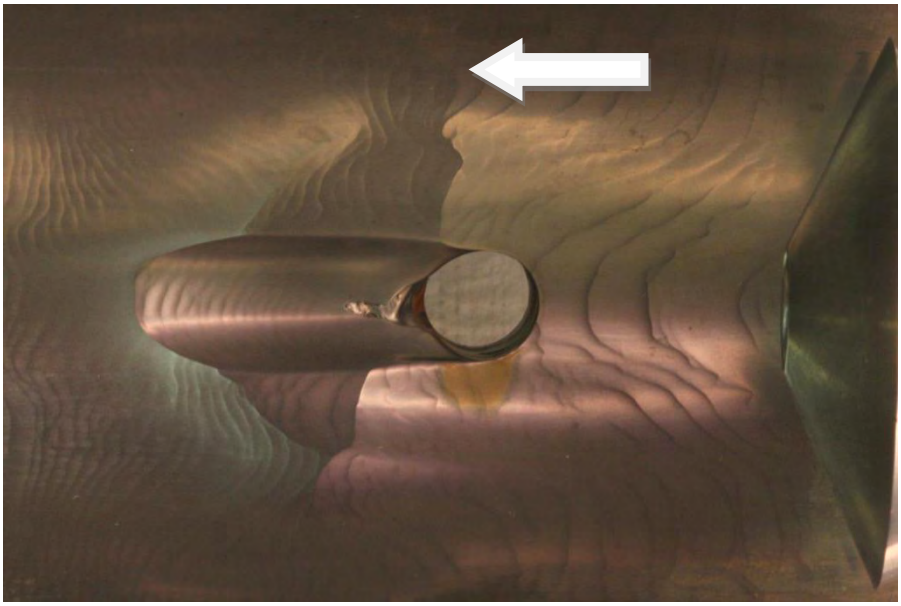


Figure 23. Photograph of the cone meter after sectioning showing erosion at the downstream wall pressure tap.

The erosion at the downstream wall tap was enough to penetrate the pipe wall, but the welded connection to the tap prevented a breach.

The Venturi is between the other two meters in terms of the pressure drop per gpm, but has very little erosion (0.001 in scar) and a very small change in C_d (0.63%). The increase in the throat bore is compensated by the low pressure tap erosion. The design of the entry cone tends to keeps the majority of sand away from the throat walls.

5.9 Flow Meter Air/Sand Erosion tests at Tulsa

The full report may be found at:
http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=609

The same three flow meters were tested in horizontal flow in an air/sand flow rig. The Venturi meter was close coupled to the wedge meter, but the test set up was a little differently as shown in the following diagram.

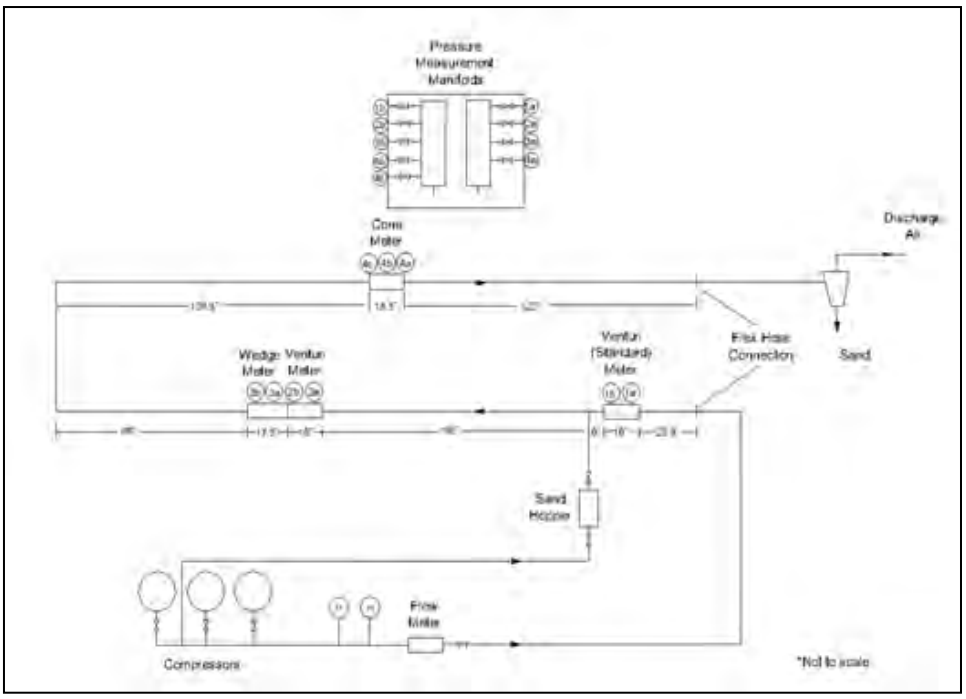


Figure 24. Schematic view of the air/sand erosion test facility at University of Tulsa.

A dual purpose facility with a nominal diameter of 2-inches was constructed to enable both flow calibration and erosion testing of flow meters. The facility is a single-pass (not re-circulatory) system. Compressed air passes through the reference meter and the test meters all of which are arranged in series. A hopper downstream of the reference meter allows sand to be introduced into the system and to flow through the test meters. The flow leaves through a cyclone separator, discharging air into the atmosphere and recovering the sand. The sand hopper is replenished as a batch process.

Table 8 . Summary of the air/sand erosion test conditions

CONDITION	VALUE
Air velocity ft/s	90.00
Air volume flow CFM	126.20
Air mass flow lb/m	12.62
Air density lb/CF	0.10
Sand volume flow CFM	0.036
Sand mass flow lb/m	6.00
Sand density lb/CF	165.00
Sand concentration % volume	0.029
Sand concentration % mass	47.54
Mixture density lb/CF	0.15
Mass of air through meters lb	6310
Mass of sand through meters lb	3000

Table 9. Calibration of flow meters before erosion

Meter	Pressure gauge (in H2O)	DP (inH2O)	Density (lb/ft³)	Cd	Velocity (ft/s)
Venturi	180	40	0.1	0.995	90
Venturi	167.5	41.5	0.0983	0.990	92
Wedge	154.5	34	0.0961	0.736	141
Cone (Base tap)	120	64.5	0.0902	0.827	98.1
Cone (Wall tap)	120	66	0.0902	0.819	98.1

Table 10. Calibration of flow meters after erosion and % difference in Cd

Meter	Cd Before Erosion	Cd After Erosion	Cd % Change	Scar in
Venturi (Master)	0.995	0.995	0.00	0.000
Venturi	0.99	0.989	-0.10	0.004
Wedge	0.736	0.805	9.38	0.126
Cone (Base tap)	0.827	1.11	34.22	0.037
Cone (Wall tap)	0.819	1.09	33.09	0.037

Table 10 shows that after 3000 pounds of sand, the change in discharge coefficient for the Venturi meter is negligible. The C_d difference when the cone meter base tap is used and when the wall tap is used is only 1%.

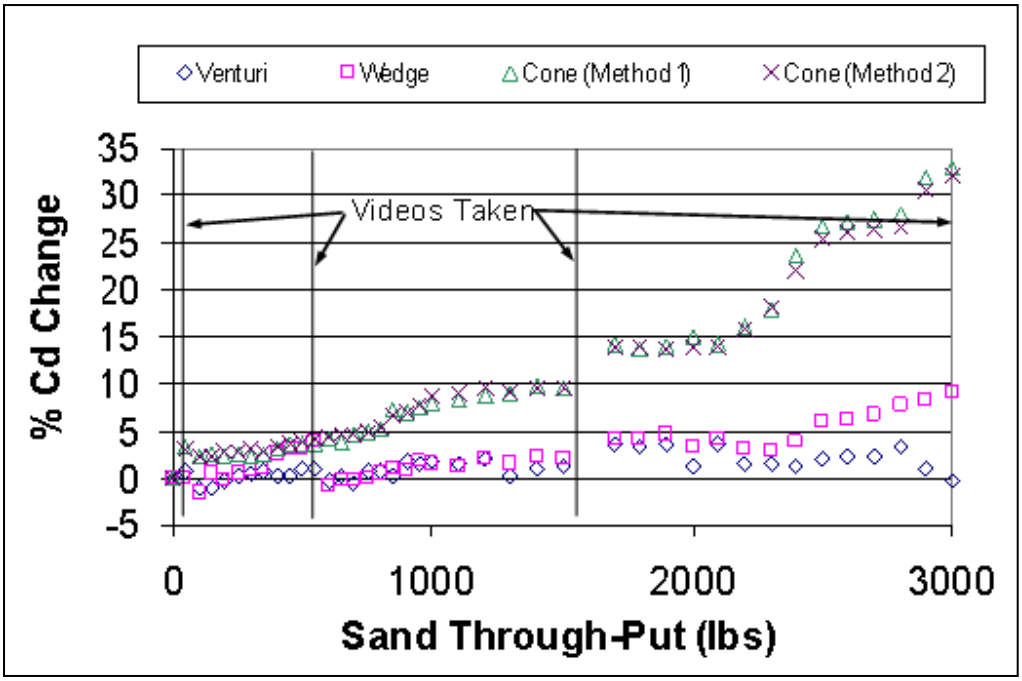


Figure 25. Shift in discharge coefficient during the University of Tulsa air-sand tests

The measured shifts in the University of Tulsa tests were less clear as step changes occurred when meters were removed for inspection (as shown in Figure 25). In Figure 26, the data has been re-plotted without offsets after 50, 550 and 1550 lb to produce continuous curves for each meter. It is believed that Figure 26 is more representative of the true shifts in discharge coefficient. The cone meter's discharge coefficient is accordingly estimated to increase by 25% and the wedge meter by 15%.

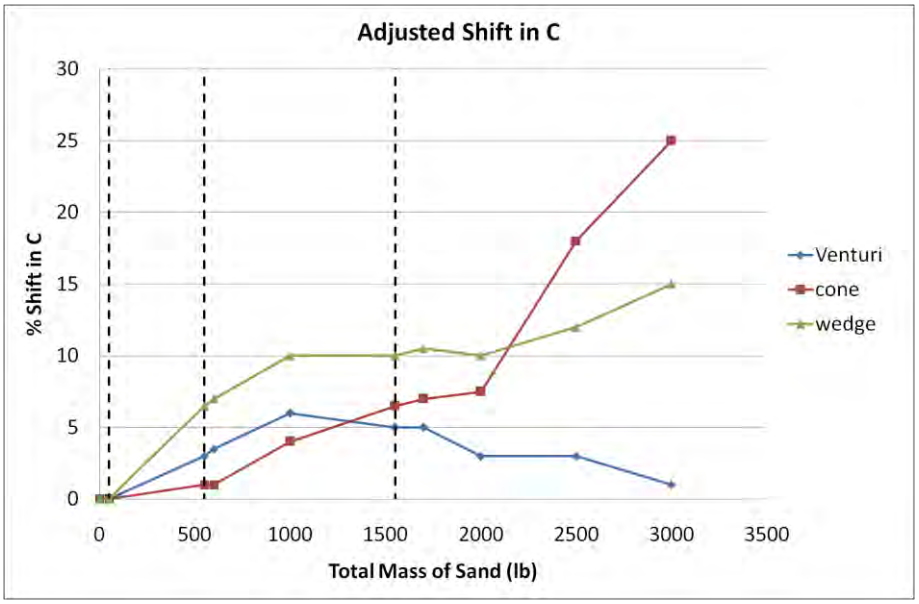


Figure 26. Adjusted shifts in discharge coefficient during the University of Tulsa air-sand tests

The erosion scar is largest on the wedge meter (0.126in), but the change in C_d is not the largest. This is because the scar is located on the upstream ramp of the downstream wedge and has little effect on the flat top of the wedge.

The erosion scar on the cone meter is only 0.037in, but the change in C_d is the largest (25%). This is because the scar is located at the annular gap between the maximum cone diameter and pipe wall, a separation distance of only 0.134-in.

5.10 Flow Meter Experimental Erosion Test Results

We can summarize the results for the three meters and two forms of erosion:

Table 11. Change in meter Cd

	Air	Water	Air/Water
Sand ton	1.5	138	0.011
Vel ft/s	100	11.2	8.93
V^2.6	158489	535	297
ton*V^2.6	237734	73764	3.22
Meter	% Cd	% Cd	Air/Water
Venturi	-0.10	-0.63	0.16
Wedge	14.95	1.72	8.69
Cone	25.03	10.77	2.32

Table 12. Scar depth and location

	Air/	Sand	Water	/Sand
Meter	Max Scar in	Location	Max Scar in	Location
Venturi	0.004	bore	0.014	bore tap
Wedge	0.126	wedge	0.343	wall
Cone	0.037	gap	0.140	wall/tap

In general, erosion depends upon both the total mass of sand passed through the meter, and upon the velocity V of the fluid raised to the power 2.6 ($V^{2.6}$). This suggests that the air/sand combination should cause more erosion than the water/sand tests. However, this is not the case. The erosion effect depends also on the meter design and where the erosion occurs.

With the Venturi meter, the entry cone tends to deflect the sand away from the throat walls, especially with air/sand, where the change in C_d (-0.1%) was found to be negligible. With water/sand, the throat tap was eroded (0.014in) but the change in C_d was still small (0.63%).

With the wedge meter and water/sand, erosion penetrated through the pipe wall (0.343in schedule 160), but the C_d did not change very much (1.72%). The air/sand mixture did not penetrate the pipe wall, but it did make a larger change in C_d (15%) by eroding the wedges.

With the cone meter, water/sand erosion penetrated the pipe wall (0.14in schedule 40) at the downstream tap, and C_d changed by 10.77%. With the air/sand mixture, erosion did not penetrate the pipe wall, but it did result in a larger change in C_d (25%) by enlarging the annular gap (0.037in) between the cone and pipe.

The actual change in C_d for the wedge and cone meter is greater with air/sand than with water/sand erosion, although the scars are not.

5.11 Flow Meter CFD Erosion Analysis Results

The full report may be found at:
http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=613

The first task was to validate the CFD erosion modeling method. Then, CFD analysis can be used to extend the range of variables beyond the limits of the experimental tests.

Comparison of CFD with SwRI Water – Sand Test

CFD simulations were performed to represent the second set of SwRI water-sand flow tests (performed for RPSEA) as closely as possible. The Venturi and wedge meter were modeled as a single unit and the cone meter was modeled separately. Table 13 shows a reasonable level of

agreement between the CFD predictions of discharge coefficient and the experimental water calibration test data in nominally ideal conditions.

Table 13. Comparison of CFD and test discharge coefficients

Meter	CFD mass rate (kg/s)	CFD dP (Pa)	D (m)	d (m)	Beta	CFD C	Test C	% diff
Venturi	7.665917	99153.98	0.052502	0.026251	0.5	0.9739	0.9968	-2.30
wedge	7.665917	57645.04	0.042901	0.030331	0.707	0.8558	0.7624	+12.25
cone	7.664035	116306.4	0.054011	0.027005	0.5	0.8495	0.7863	+8.031

Figure 27 compares photographs of the wedge meter internals at the conclusion of the water-sand erosion tests with the CFD erosion predictions. The CFD predictions for the Venturi-wedge meter combination failed to predict the erosion that was found experimentally on the Venturi pressure taps. On the other hand, erosion on the convergent section of the Venturi was, qualitatively, predicted correctly.

For the wedge meter, scouring on the wedges and the deep scars on the meter's walls were correctly predicted by CFD analysis. The upstream and downstream scars were predicted to be about 1.4 mm and 4.6 mm respectively compared to 3.4 and 8.6 mm seen in the tests. Rounding of the edges of the wedges was over-estimated by CFD analysis.

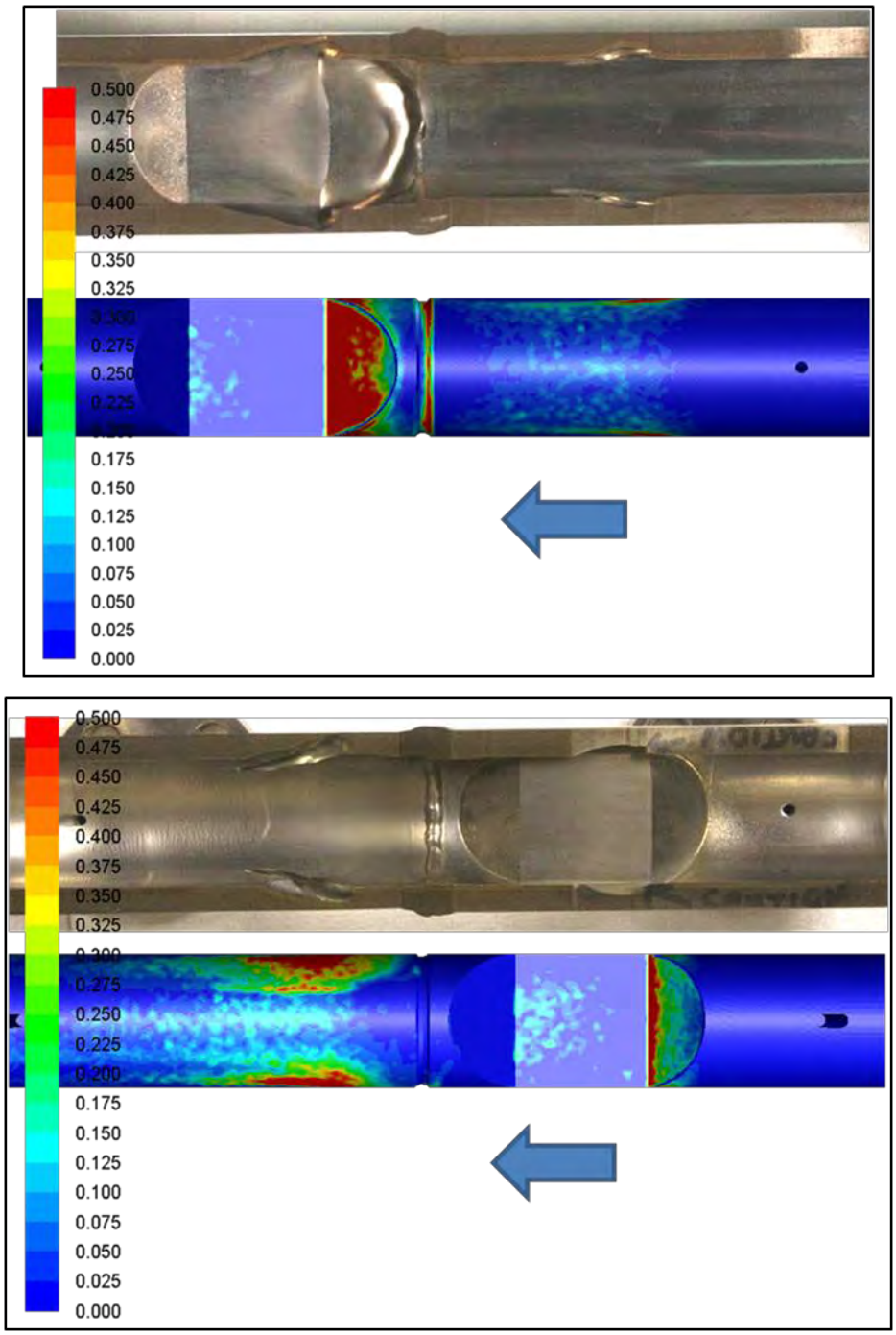


Figure 27. Erosion distribution in the beta = 0.707 wedge meter – SwRI water-sand test and CFD analysis (mm)

Figure 28 compares photographs of the cone meter after the erosion tests were completed with the CFD erosion predictions. CFD analysis over predicted the rounding of the edge of the cone. CFD analysis predicted a cone diameter reduction of about 2.4 mm compared to 0.87 mm found in the tests. Also, erosion on the walls, in the wake of the cone, occurred further downstream in

the CFD simulations than in the experiments. The maximum predicted scar depth from CFD analysis was 0.4 mm compared to 1.1 mm in the tests.

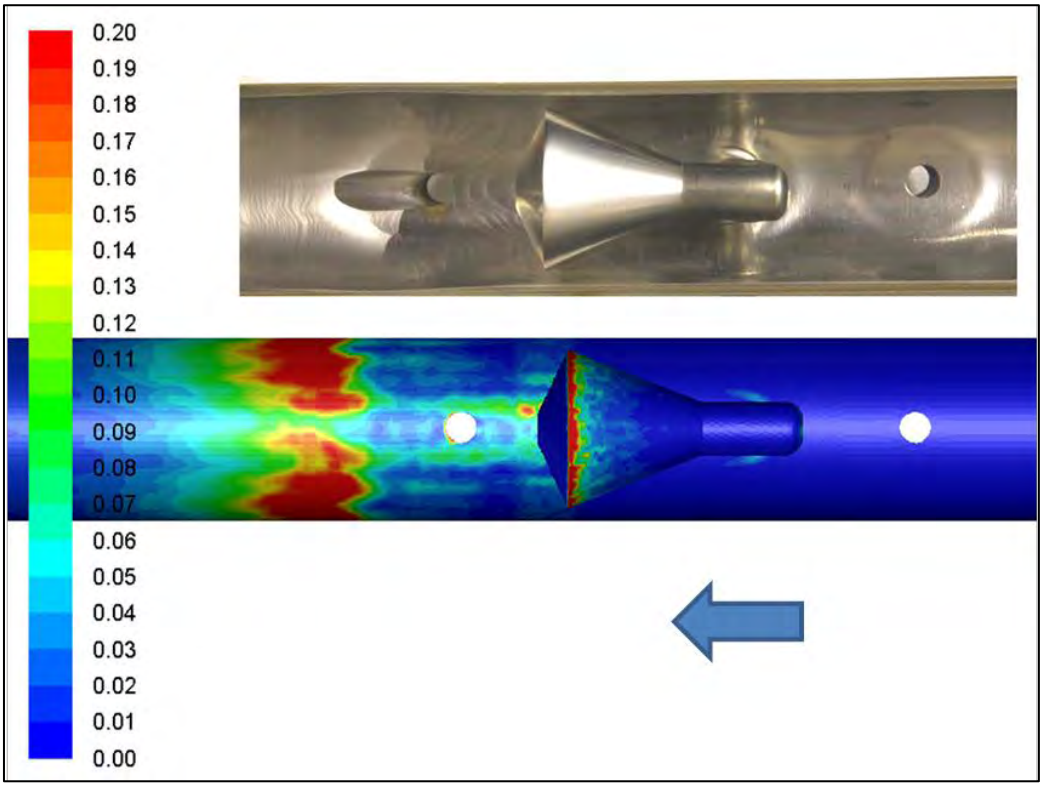


Figure 28. Erosion distribution in the beta = 0.5 cone meter – SwRI water-sand test and CFD analysis (mm)

In the previous cone meter project (App C), a ballpark estimate was made of shifts in discharge coefficient of +40% and -1% for the cone and Venturi under the original test conditions. Rescaling these values to allow for the lower total sand mass flux in the latest test produces estimates of +16.6% and -0.4% compared to measured values of +10.77% and -0.63%.

Overall, the agreement between the tests and CFD is as good as can be expected, given the simplifications and assumptions used in the simulation method.

Comparison of CFD with University of Tulsa Air – Sand Test

Figure 29 shows a reasonable agreement between test and CFD simulations with the erosion distribution being reliably identified. There were distinct differences in the erosion patterns in water and air tests and the CFD predicted these differences reasonably well.

The groove in the wall next to the cone is predicted to be about 0.95 mm deep compared to measured value of about 0.94 mm. The predicted reduction in cone diameter is about 2.2 mm compared to a measured value of about 1.8 mm.

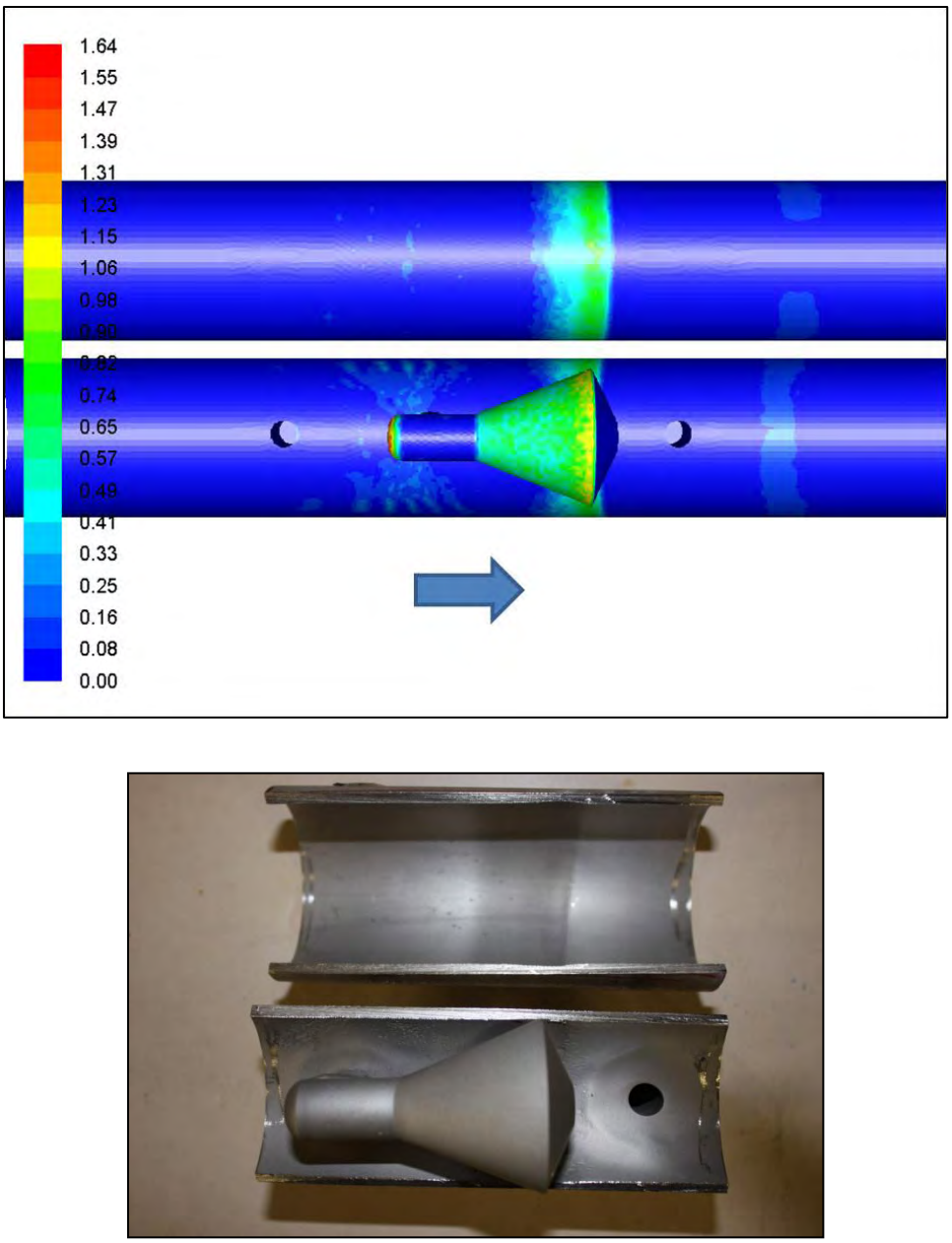


Figure 29. Comparison of CFD predictions and the eroded cone meter (air-sand)

Figure 30 shows that the agreement between experiment and CFD with the Venturi-wedge meter is not as good, but still reasonable for an erosion prediction. The maximum erosion on the front face of the downstream wedge is about 4.3 mm compared with a maximum predicted value of 8.1 mm.

The CFD incorrectly predicted marginally higher erosion on the upstream wedge whereas in reality the downstream wedge was most affected.

The measured wall thickness reduction is 2.8 mm and 1.1 mm adjacent to the upstream and downstream wedges respectively. This compares to predicted values of 3 mm in both locations.

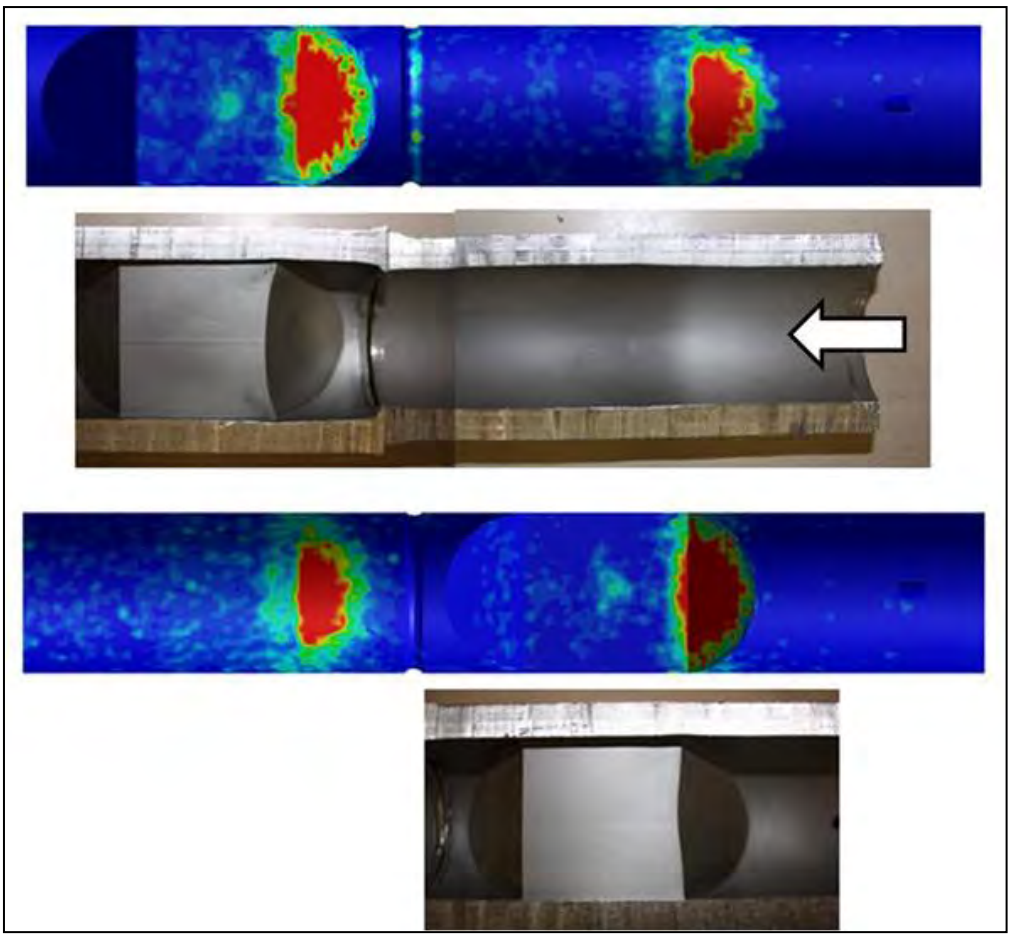


Figure 30. Comparison of CFD air-sand erosion predictions for the wedge meter

5.12 Further CFD Simulations

A large number of CFD simulations were run to assist in the development of equations that would facilitate development methods for estimating erosion and the shift in discharge coefficient. The CFD method modeled the primary erosion scars in cone meters and wedge meters with reasonable reliability.

In Venturi meters, the most significant erosion scar occurs in the throat and throat tapping. The standard modeling method failed to predict this erosion. It was therefore decided to develop the erosion equations for the Venturi meter based primarily on the test results with some supplemental CFD simulations, using a modified modeling approach, for extrapolation purposes.

Venturi meters, cone meters and wedge meters all cause a flow restriction. This can significantly elevate erosion in elbows and other fittings downstream of the flowmeter. This is particularly important in subsea installations, which often include bends close to meter outlets.

5.13 CFD Simulations of Erosion in Cone Meters

A series of simulations were run with the following range of parameters:

- Beta = 0.45 to 0.85
- Water and air assumed at STP, with GVFs ranging from 0 to 100%
- Sand sizes from 50 to 500 microns
- Pipe velocities from 3.5 to 60 m/s
- Pipe diameters from 2 to 12 inches

These parameters were chosen to extend the test of one 2-inch beta = 0.5 cone meter in air/sand and water/sand slightly beyond the range of conditions likely to occur in a subsea installation.

Water-air flows were modeled as a homogenous single phase fluid with the density and viscosity calculated based on the gas volume fraction. This is a fairly standard and proven approach in CFD erosion modeling. Hence a fluid with a density of 200 kg/m^3 may represent a wet gas flow or a dry gas flow at high pressure. A fluid of density 800 kg/m^3 may represent a single phase light oil flow or a high water-cut, low gas volume fraction multiphase mixture.

Predictions are made for the depth of the scar on the pipe wall downstream of the cone for a beta = 0.45 cone meter. This scar was chosen as the test results indicate that this point (and the scar in the downstream tapping) is the most likely location of a pipe wall penetration.

Figure 31 shows that erosion is highly dependent on the mean pipe velocity as expected.

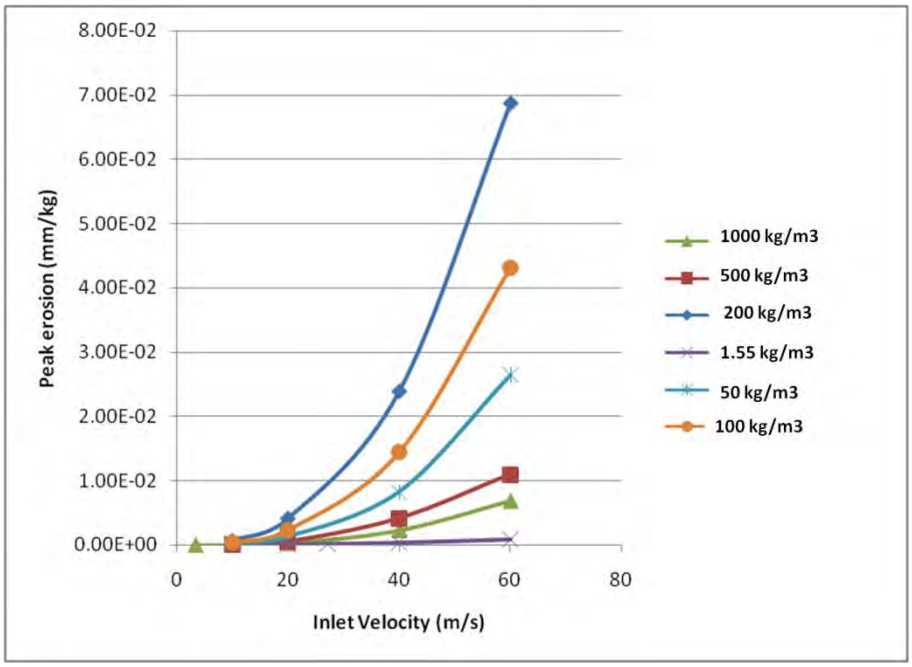


Figure 31. Variation of erosion in the pipe wall downstream of a beta = 0.45 cone meter with pipe velocity (250 micron particles)

There is a strong dependence on the fluid mixture density. Low density fluids do not impart much drag on the sand particles. As the particles pass through the throat, they are barely accelerated before they hit the pipe wall. High density fluids quickly accelerate particles to the throat velocity. However, high-turbulence downstream of the throat effectively disperses the particles before they impact. In medium-density fluids, particles accelerate significantly in the throat and they hit the walls in a highly concentrated jet. Hence the peak erosion rate occurs for fluid mixtures with a density of about 200 kg/m^3.

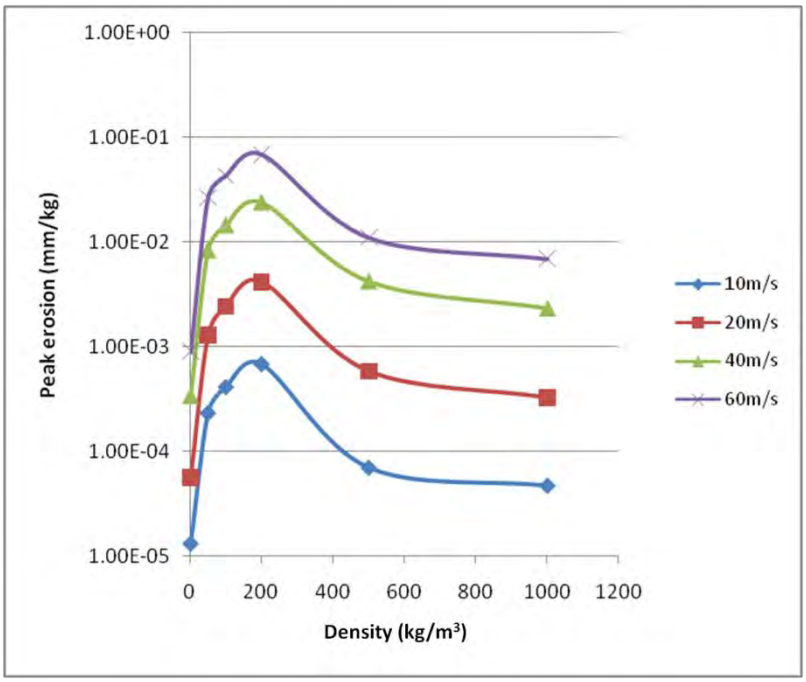
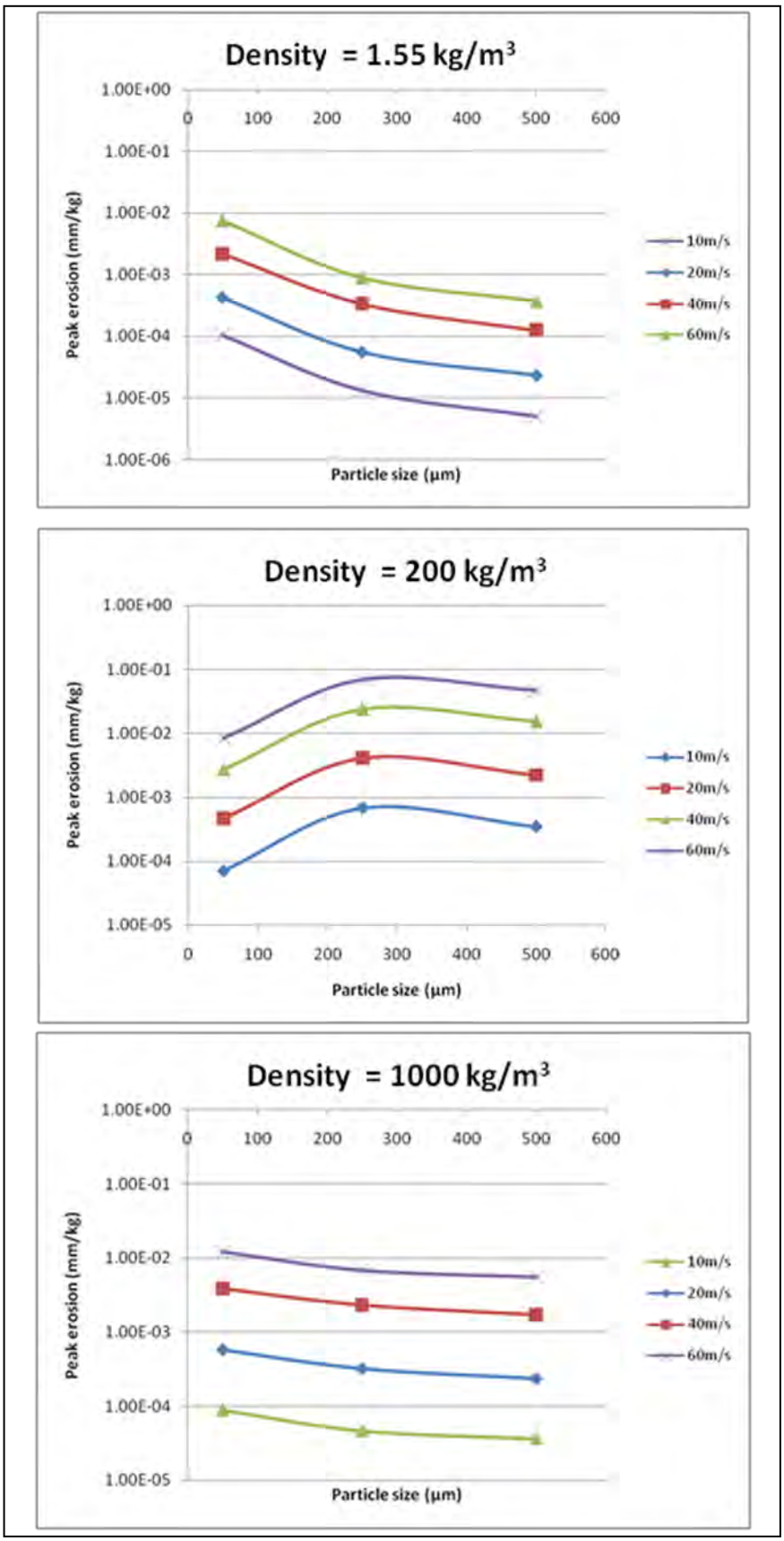


Figure 32. Variation of erosion in the pipe wall downstream of a beta = 0.45 cone meter with fluid density (250 micron particles)

There is a much weaker dependence on particle size. As small particles are more easily accelerated than large ones, the particle size will influence the fluid density at which the maximum erosion will occur. However, small particles are also more easily perturbed by fluid turbulence and this will complicate matters by changing the frequency and concentration of wall impacts. This is probably why there is no clear pattern of behavior as the fluid density varies.



Figures 33a-c. Variation of erosion in the pipe wall downstream of a beta = 0.45 cone meter with particle size

Figure 34 shows that erosion decreases as the meter size increases.

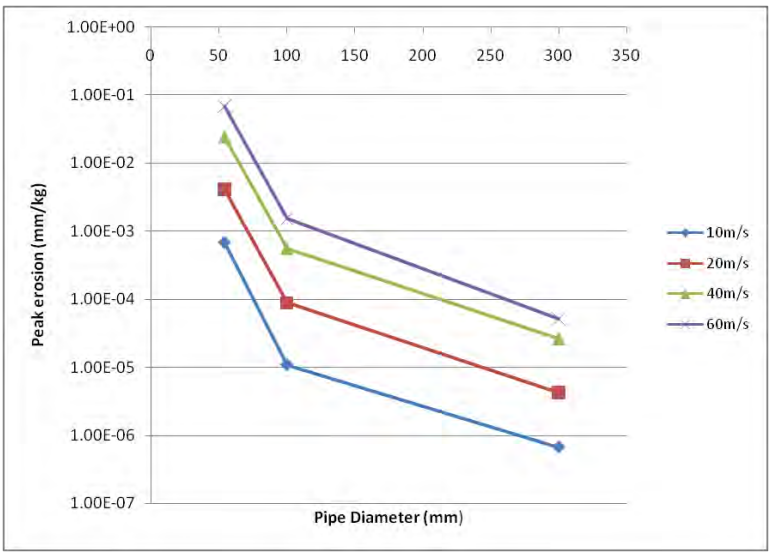


Figure 34. . Variation of erosion in the pipe wall downstream of a beta = 0.45 cone meter with pipe size (250 micron particles)

5.14 CFD Simulations of Erosion in Wedge Meters

A series of simulations were run with the following range of parameters:

- Beta = 0.707 only
- Water and air assumed at STP, with GVFs ranging from 0 to 100%
- Sand sizes from 50 to 500 microns
- Pipe velocities from 3.5 to 60 m/s
- Pipe diameters from 2 to 12 inches

Erosion increases significantly with the mean pipe velocity, as in the cone meter.

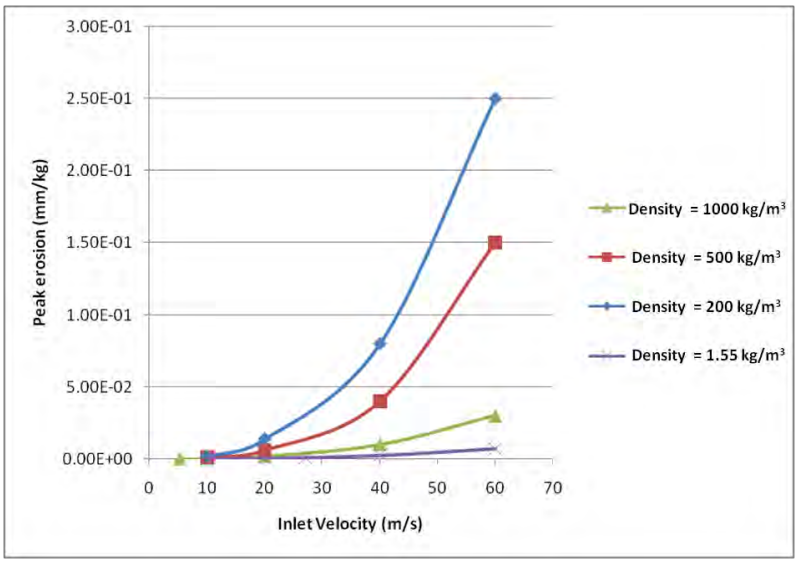


Figure 35. Variation of erosion in the pipe wall of a wedge meter with pipe velocity

There are similar effects of fluid density, with the maximum erosion occurring for 200 kg/m^3 fluids.

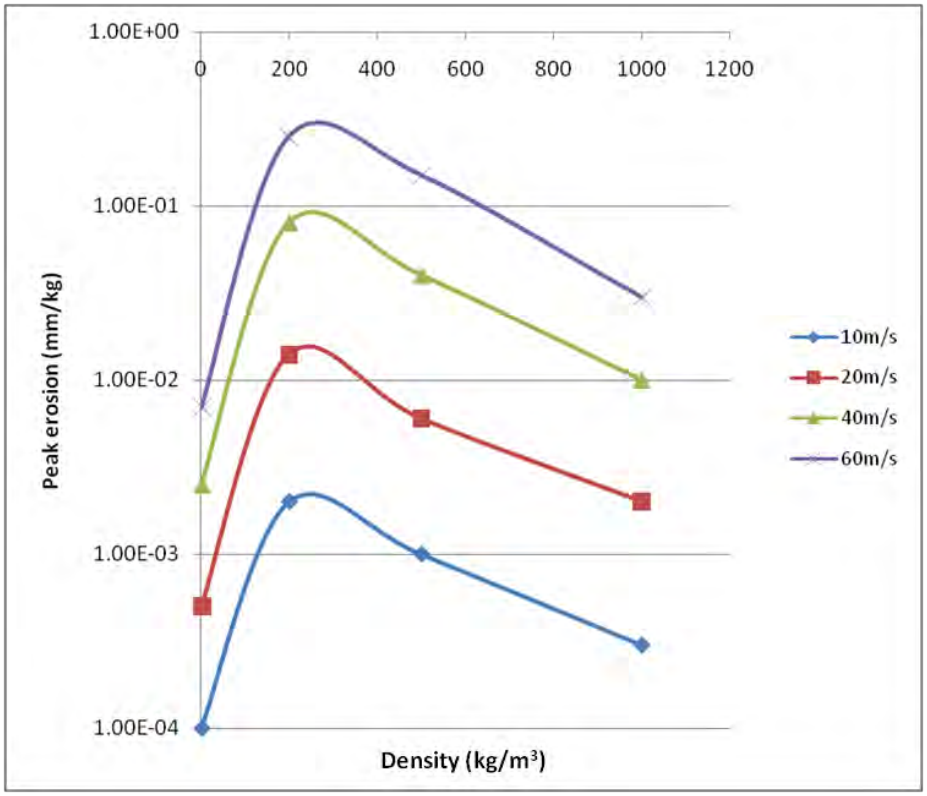


Figure 36. Variation of erosion in the pipe wall of a wedge meter with fluid density

Particle size effects are relatively small and slightly less than in the cone meter. This may be because the wedge meter has a lower effective beta ratio and hence particle acceleration effects are less.

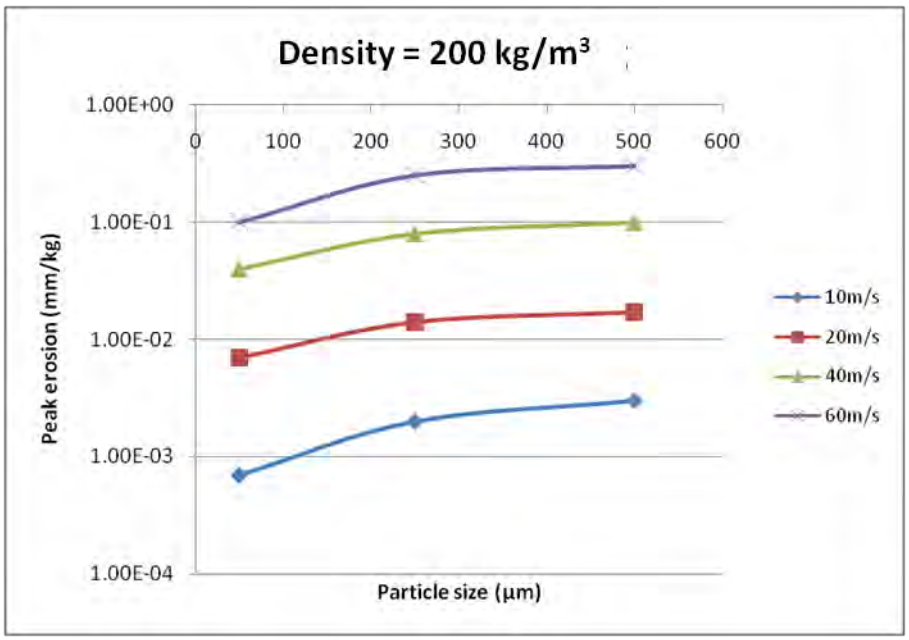


Figure 37. Variation of erosion in the pipe wall of a wedge meter with particle size

With the wedge meter, as in the cone meter, erosion is less in larger meters.

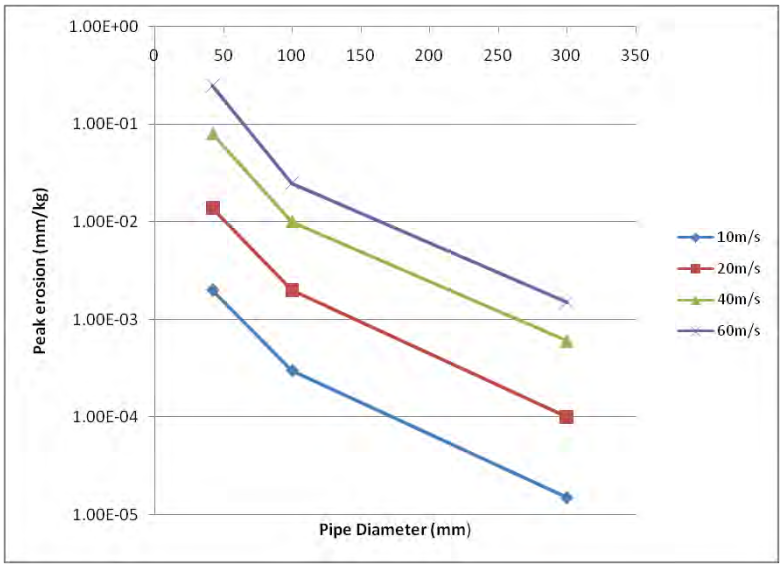


Figure 38. Variation of erosion in the pipe wall of a wedge meter with pipe size

5.15 Effect of Flowmeters on Erosion of Downstream Elbows

A series of simulations was run in which a 1.5D radius elbow was installed at different distances downstream of a 2-inch beta = 0.4 Venturi, a beta = 0.45 cone meter and a beta = 0.707 wedge meter. These beta ratios were chosen to represent near-worst case scenarios. The pipe velocity was set to 20 m/s. The carrying fluid was set to be water, gas or air, with respective densities of 1000 kg/m^3, 50 kg/m^3 and 1.225 kg/m^3. The particle size was set to 250 microns.

Figures 39a-c show particle tracks from three Venturi simulations with the elbow at a distance of 3 pipe diameters. In these figures, the particle trajectories are colored by velocity (m/s) for the Venturi and elbow simulations. In air flow (1.225 kg/m^3), the air produces only a little drag on the particles. Hence relatively little particle acceleration occurs in the Venturi throat. The particles tend to bounce off surfaces and travel in straight lines before bouncing off other surfaces. The particle trajectories are dominated by their bounce behavior. The current CFD model assumes perfectly spherical particles, all with the same bounce behavior. This would not happen in practice as sand particles are non-uniform in shape and their bounce behavior varies significantly, depending on which side of a particle first impacts the wall. It is therefore believed that the current CFD model may produce misleading predictions in some of the air-sand flow models run.

In gas flow (50kg/m^3), the particle behavior is very different. The higher density fluid effectively accelerates the particles and a concentrated jet is formed downstream of the Venturi. This increases the velocity with which particles impact the downstream elbow and particles impact on a smaller area. Hence erosion may be significantly accelerated in the downstream elbow.

In water flow (1000 kg/m^3), particles are accelerated to the maximum throat velocity. However, slower fluid downstream of the Venturi decelerates the particles before they impact. Also, high levels of turbulence downstream quickly dissipate the particle jet issuing from the Venturi throat. Hence, in this case, most erosion occurs with the medium density fluid case.

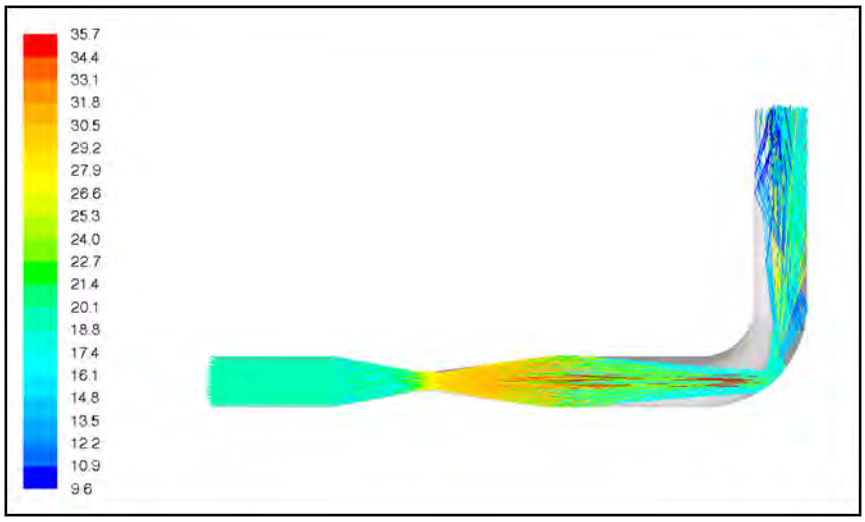


Figure 39 a. Particle trajectories in a Venturi meter flowing air

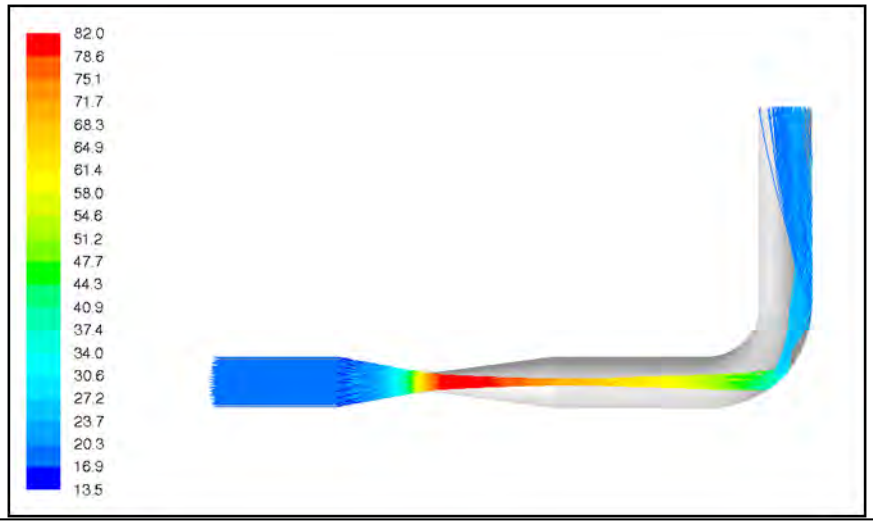


Figure 39 b. Particle trajectories in a Venturi meter flowing gas

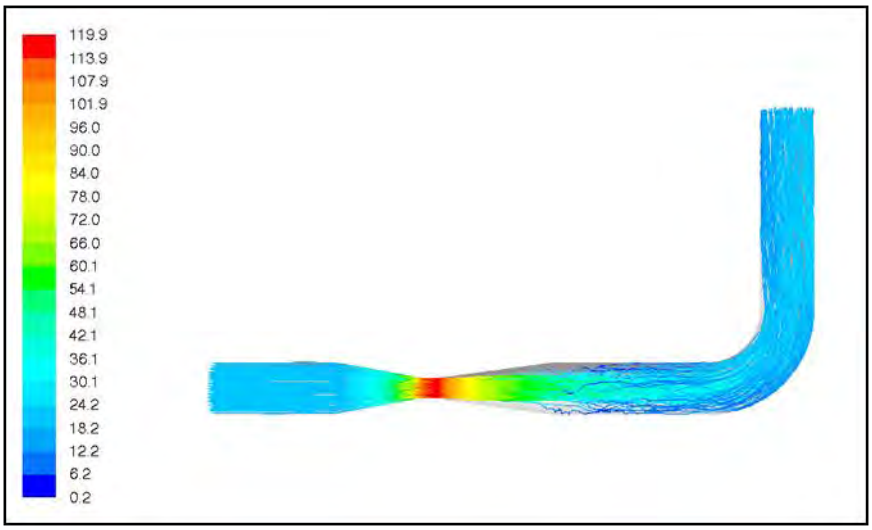


Figure 39 c. Particle trajectories in a Venturi meter flowing water

Figure 39. Particle trajectories in a Venturi meter flowing air, gas and water

Figures 40a, b and c show the effect of upstream flowmeters on downstream elbows at different distances. In these graphs, the increase in erosion caused by the upstream flowmeter is plotted in terms of an erosion enhancement factor, defined as the erosion in the elbow downstream of the flowmeter divided by the erosion that would have occurred if there was no flow restriction upstream of the elbow.

The spike seen in Figure 40c, the Venturi air graph at 2D, is an artifact produced by the overly uniform bounce behavior of the spherical particles, as previously discussed.

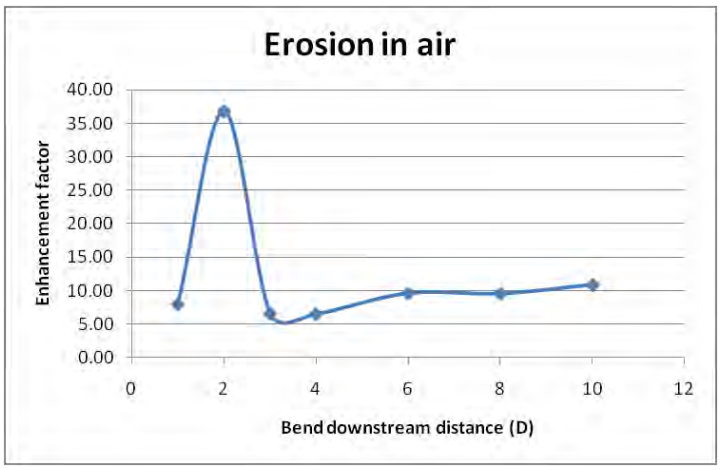


Figure 40a. Predicted erosion of an elbow downstream of a beta = 0.4 Venturi for a mean pipe flow velocity of 20 m/s flowing air

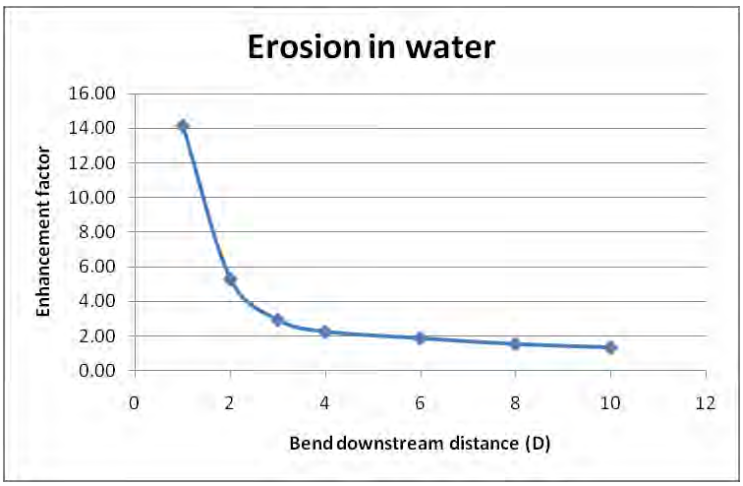


Figure 40b. Predicted erosion of an elbow downstream of a beta = 0.4 Venturi for a mean pipe flow velocity of 20 m/s flowing water

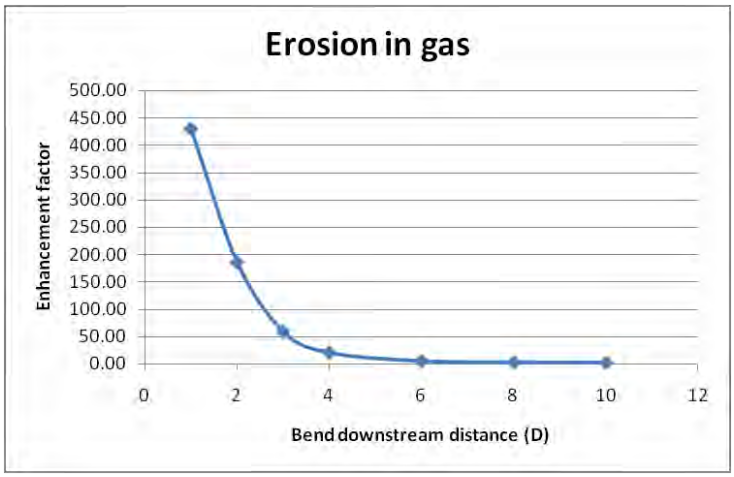


Figure 40c. Predicted erosion of an elbow downstream of a beta = 0.4 Venturi for a mean pipe flow velocity of 20 m/s flowing gas

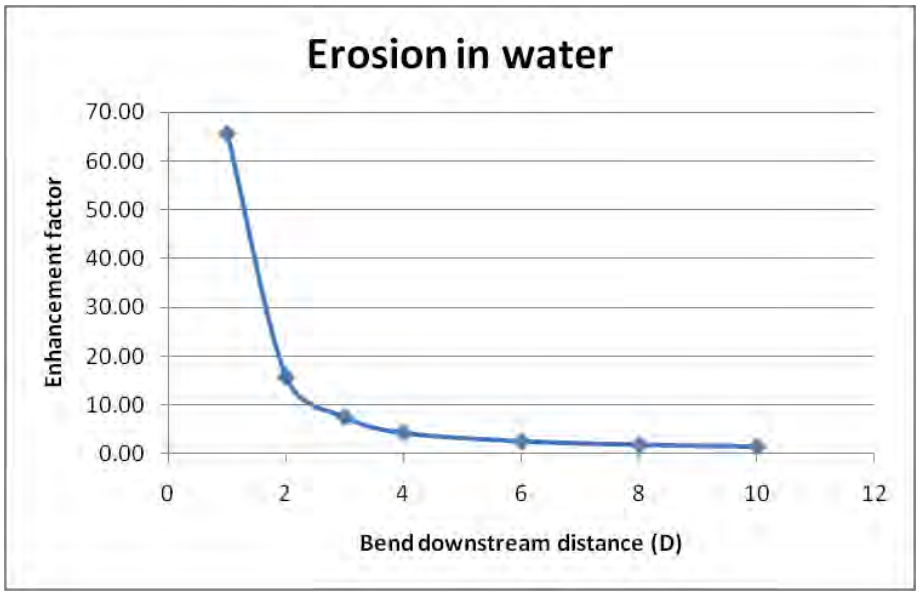


Figure 41a. Predicted erosion of an elbow downstream of a beta = 0.45 cone meter for a mean pipe flow velocity of 20 m/s flowing water

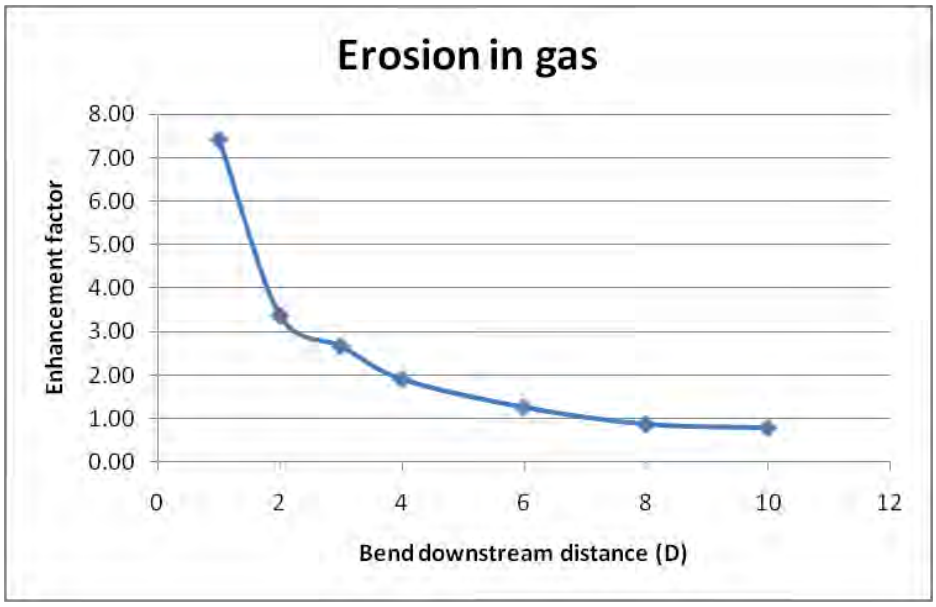


Figure 41b. Predicted erosion of an elbow downstream of a beta = 0.45 cone meter for a mean pipe flow velocity of 20 m/s flowing gas

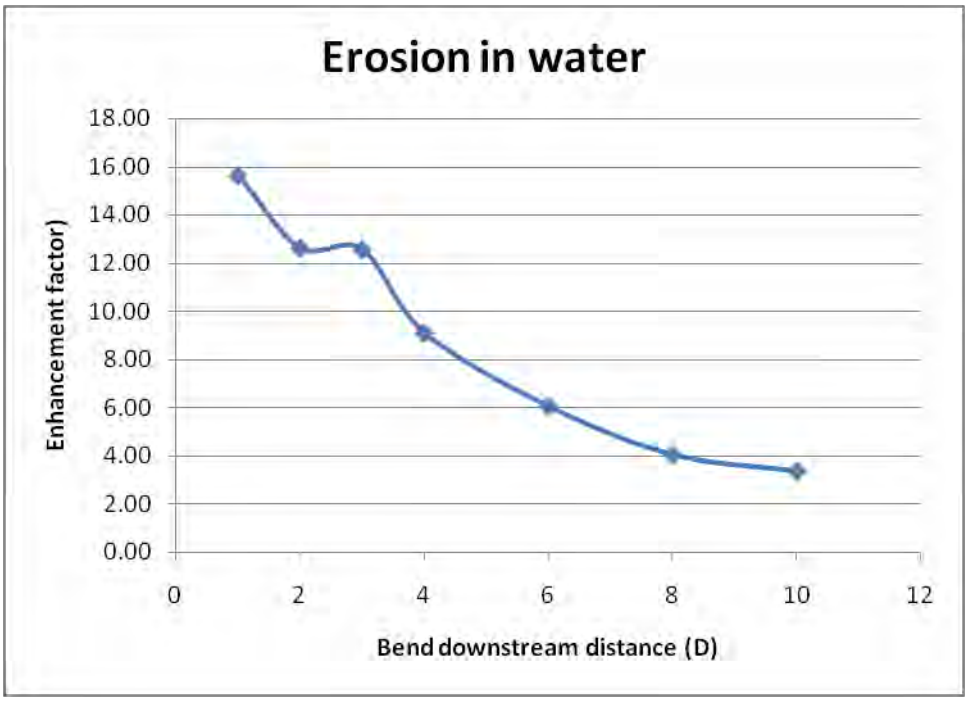


Figure 42a. Predicted erosion of an elbow downstream of a beta = 0.707 wedge meter for a mean pipe flow velocity of 20 m/s flowing water

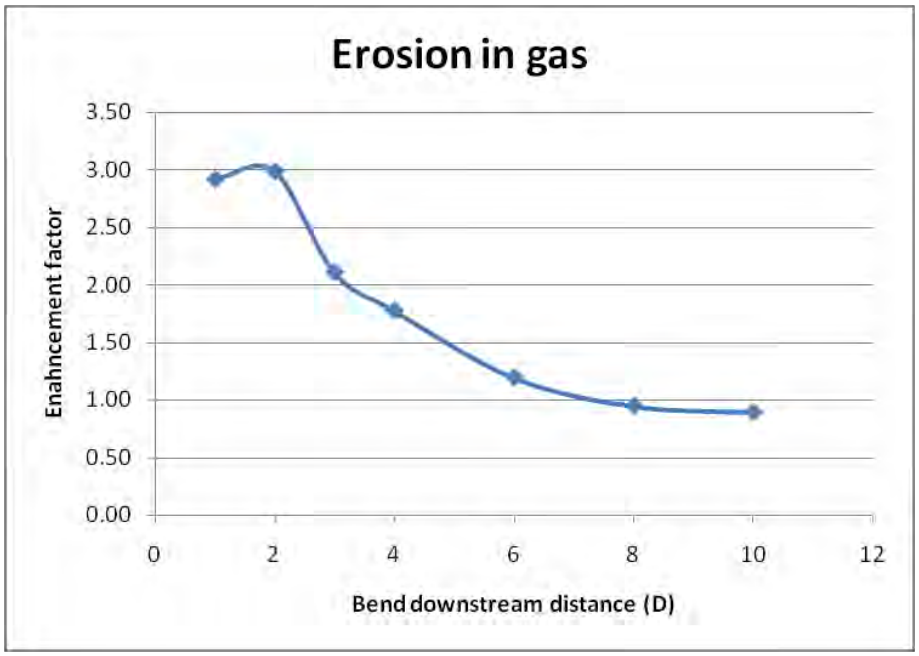


Figure 42b. Predicted erosion of an elbow downstream of a beta = 0.707 wedge meter for a mean pipe flow velocity of 20 m/s flowing gas

All of the flow meters cause accelerated erosion in the downstream elbow. Increasing the distance between the meter and the elbow reduces erosion in the elbow. Beyond 5D separation the interaction becomes negligible.

The worst case modeled is the Venturi meter in gas flow (figure 40c). The erosion in an elbow downstream of a beta = 0.4 Venturi in gas flow may be accelerated by a factor of 430. In water flow, the beta = 0.45 cone meter is the worst case, with a maximum enhancement factor of about 67. The beta = 0.707 wedge meter causes the least effect, with a maximum enhancement factor of about 16, probably because it has the highest beta ratio.

This exercise demonstrates that flow-restricting meters can potentially cause significant increases in the erosion rates in elbows and other pipe work fixtures located downstream of the meter. This is particularly true if the meter has a small beta ratio or if, as likely in many subsea installations, there are less than five diameters of straight pipe downstream of the meter. The degree of erosion enhancement will depend on the particle size, the meter geometry and the fluid density, among other factors. Development of a reliable equation which could model this complex scenario would be impractical. It is suggested that this type of issue would be best addressed by means of CFD simulation or testing of individual installation designs.

5.16 Development of Erosion Prediction Equations

This section provides the erosion prediction equations, gives information on how they were developed, and their limitations.

Venturi meter

The primary erosion damage in Venturi meters occurs in the throat. As the throat is usually the thickest part of the Venturi wall it is unlikely that a wall penetration failure will occur in the Venturi itself. It is more likely that an elbow located downstream of the Venturi will fail, as discussed in Section 6.15.

For completeness, a basic erosion equation has been developed to estimate erosion in a Venturi throat. The standard CFD simulation method used in this study did not predict any significant erosion in the throat. The reason for this is believed to be that either the intensity of the flow turbulence near the Venturi throat walls was under-estimated or that the particle response to turbulence was too weak.

In the ANSYS FLUENT CFD package, the effect of the random buffeting of turbulent eddies on particles is simulated by subjecting each particle to additional random forces. The magnitude of these random fluctuations is controlled by the predicted turbulence intensity and a coefficient C_L. The default value of C_L is 0.15. This value is based on kinetic theory. Increasing C_L increases the number of random wall impacts of particles travelling close to the throat wall, as shown below in Figures 43a and 43b.

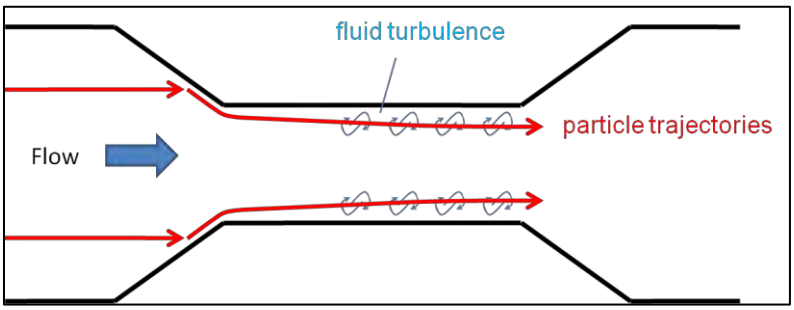


Figure 43a. Illustration of the effect of varying the CL parameter in a Venturi meter. CL = 0.15

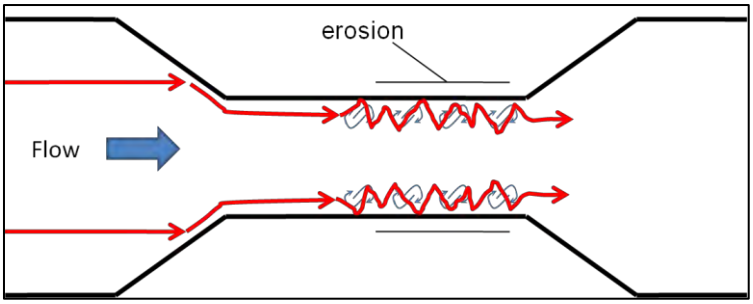


Figure 43b. Illustration of the effect of varying the CL parameter in a Venturi meter. CL = 5.

If C_L is increased to 5 or more, then good agreement is achieved with the test measurements of throat wall erosion.

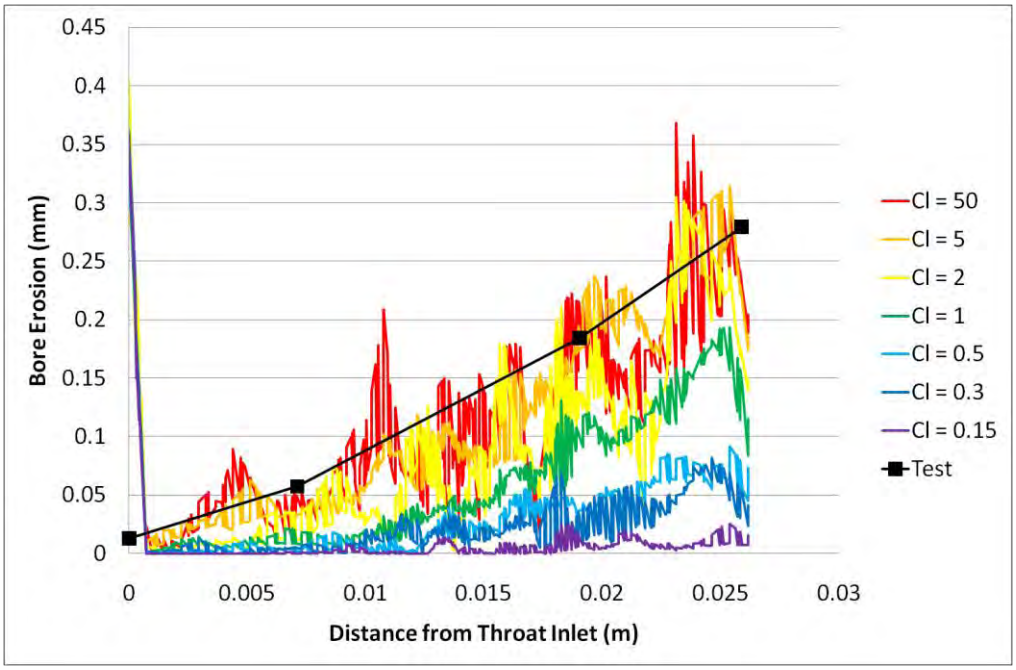


Figure 44. Effect of varying the CL parameter on erosion in a Venturi throat

While increasing C_L from 0.15 to 5 gives a much better agreement with test data, the validity of changing C_L to match the test data is somewhat dubious. However, it does provide a tentative method for supplementing the limited number of test measurements when developing the erosion equation.

The following equations are proposed to model erosion in a Venturi throat:

$$E_v = c_v \frac{m_{sand}}{\rho_{metal}} k V_{throat}^n \qquad \text{(Equation 5)}$$

$$V_{throat} = \frac{Q}{\left(\frac{\pi . d_{throat}^2}{4}\right)} \qquad \text{(Equation 6)}$$

Where:

E_v is the maximum increase in throat diameter over the time period (mm)

c_v is a constant = 3140

m_{sand} is the total mass of sand passed through the Venturi in the time period (kg)

V_{throat} is the mean fluid velocity in the Venturi throat (m/s)

Q is the actual volumetric fluid flow rate through the meter (m^3/s)

d_{throat} is the throat diameter (m)

ρ_{metal} is the density of the construction material of the Venturi throat is (kg/m^3)
(ρ_{metal} = 7850 kg/m^3 for steel grade materials)

k is a material constant (k = 2 x 10^{-9} for steel grade materials)

n is a material constant (n = 2.6 for steel grade materials)

Note that appropriate values of k and n for materials other than steel grade material can be found in two references[3] [4].

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[3] DET NORSKE VERTITAS. Recommended practice RP 0501: Erosive Wear in Piping Systems. 1996 , Revision 1999.

[4] HAUGEN, K., KVERNVOLD, O., RONOLD, A. & SANDBERG, R. *Sand erosion of wear-resistant materials: erosion in choke valves.* Wear 186-187, pp 179-188, 1995

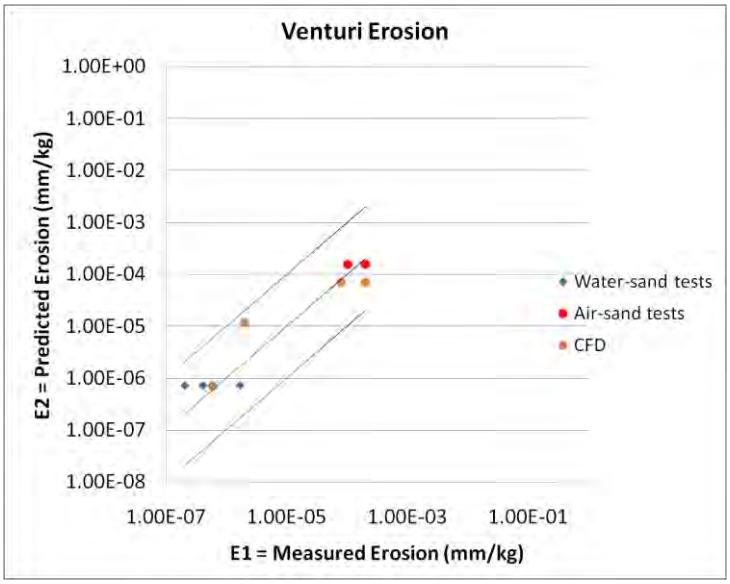

Figure 45. Comparison of measured and CFD simulated erosion in the throat of a beta 0.5 Venturi meter with the predictions of equation 5

Equation 5 should only be regarded as being valid for 2-inch beta = 0.5 Venturi as test data was only available for this size of meter. However, the limited number of additional CFD runs, which used the modified value of C_L also agree moderately well with the equation. The method should be valid for liquid, gas and multiphase flows over the full range of fluid densities and particles sizes likely to be encountered subsea.

Cone Meters

The following equation was developed to produce an estimation method for erosion on the pipe wall, downstream of the cone of a cone meter.

$$E_c = c_c \frac{m_{sand}}{\rho_{metal}} k V_{throat}^n \qquad \text{Equation 7}$$

$$V_{throat} = \frac{Q}{\left(\frac{\pi d_{pipe}^2}{4} - \frac{\pi d_{cone}^2}{4} \right)} \qquad \text{Equation 8}$$

Where:

E_c is the maximum depth increase in the pipe wall scar over the time period (mm)

c_c is a constant = 11775

m_{sand} is the total mass of sand passed through the meter in the time period (kg)

V_{throat} is the mean fluid velocity in the cone throat (m/s)

Q is the actual volumetric fluid flow rate through the meter (m3/s)

d_{pipe} is the pipe diameter (m)

d_{cone} is the cone diameter (m)

ρ_{metal} is the construction material density of the cone meter (kg/m3)

(ρ_{metal} = 7850 kg/m3 for steel grade materials)

k is a material constant (k = 2 x 10-9 for steel grade materials)

n is a material constant (n = 2.6 for steel grade materials)

Equation 7 produces an estimate (see Figure 46 below) with no obvious bias that consistently predicts erosion within an order of magnitude of test measurements and CFD simulations. The method applies to 12 inch meters, or smaller and over a beta range of from 0.45 to 0.85.

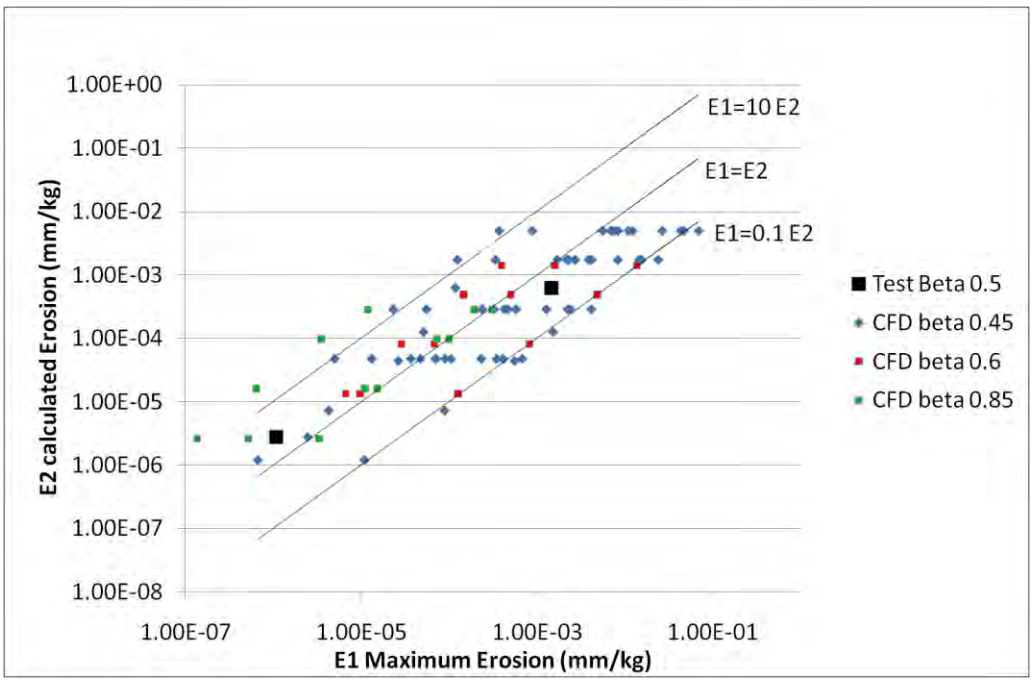

Figure 46. Comparison of measured and simulated erosion on the pipe wall downstream of a cone with the predictions of equation 7

Wedge Meters

Equation 9 has been developed to estimate erosion in the pipe wall, immediately next to the wedge:

$$E_w = c_w \frac{m_{sand}}{\rho_{metal}} d_{pipe}^{-2.5} k V_{pipe}^{n} \qquad \text{Equation 9}$$

$$V_{pipe} = \frac{Q}{\left(\frac{\pi d_{pipe}^2}{4}\right)}$$ Equation 10

Where:

E_w is the maximum depth increase in the pipe wall scar over the time period (mm)

c_w is a constant = 1570

m_{sand} is the total mass of sand passed through the meter in the time period (kg)

V_{pipe} is the mean fluid velocity in the pipe (m/s)

Q is the actual volumetric fluid flow rate through the meter (m^3/s)

d_{pipe} is the pipe diameter (m)

ρ_{metal} is the construction material density of the wedge meter (kg/m^3)
(ρ_{metal} = 7850 kg/m^3 for steel grade materials)

k is a material constant ($k = 2 \times 10^{-9}$ for steel grade materials)

n is a material constant (n = 2.6 for steel grade materials)

Figure 47 show that it produces a reasonable agreement with CFD and test data points. The method should be valid for, liquid, gas and multiphase flows over the full range of fluid densities and particles sizes likely to be encountered subsea.

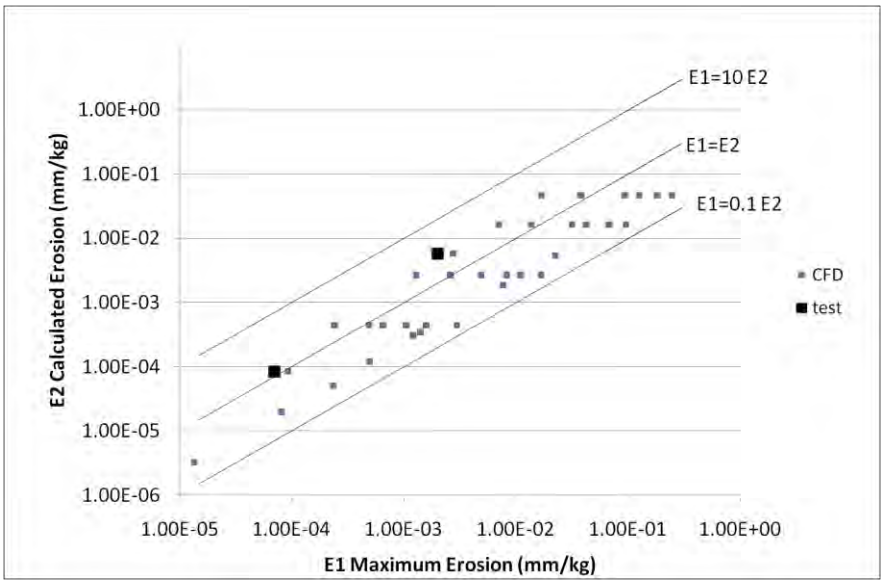

Figure 47. Comparison of measured and simulated erosion on the pipe wall of a wedge meter with the predictions of equation 9

Taps

As with the Venturi throat, prediction of erosion of the taps has been difficult because the standard CFD method was not able to accurately predict this phenomenon. Hence only test data has been used to develop the following model.

$$E_t = c_t m_{sand} V_0^2 \qquad \text{Equation 11}$$

Where:

E_t is the maximum depth increase in the pipe wall scar over the time period (mm)

c_t is a constant = 6.0×10^{-7} for taps downstream of a cone or wedge

c_t is a constant = 1.6×10^{-7} for upstream taps and Venturi throat tappings

m_{sand} is the total mass of sand passed through the Venturi in the time period (kg)

V_0 is the mean fluid velocity in the pipe, Venturi throat or cone throat (m/s)

As very little information is available on the maximum depth of erosion downstream of the tapping, the method predicts the length of the erosion scar downstream of the tapping in the direction of the flow. A conservative assessment approach would assume that, in the absence of better information, the depth of the scar is equal to its length. It should also be noted that this equation only applies to steel and steel grade materials including Stellite and Inconel. Figure 48 shows that this approach produces a reasonable agreement with the limited test data available. The method should be valid for liquid, gas and multiphase flows over the full range of fluid densities and particles sizes likely to be encountered subsea.

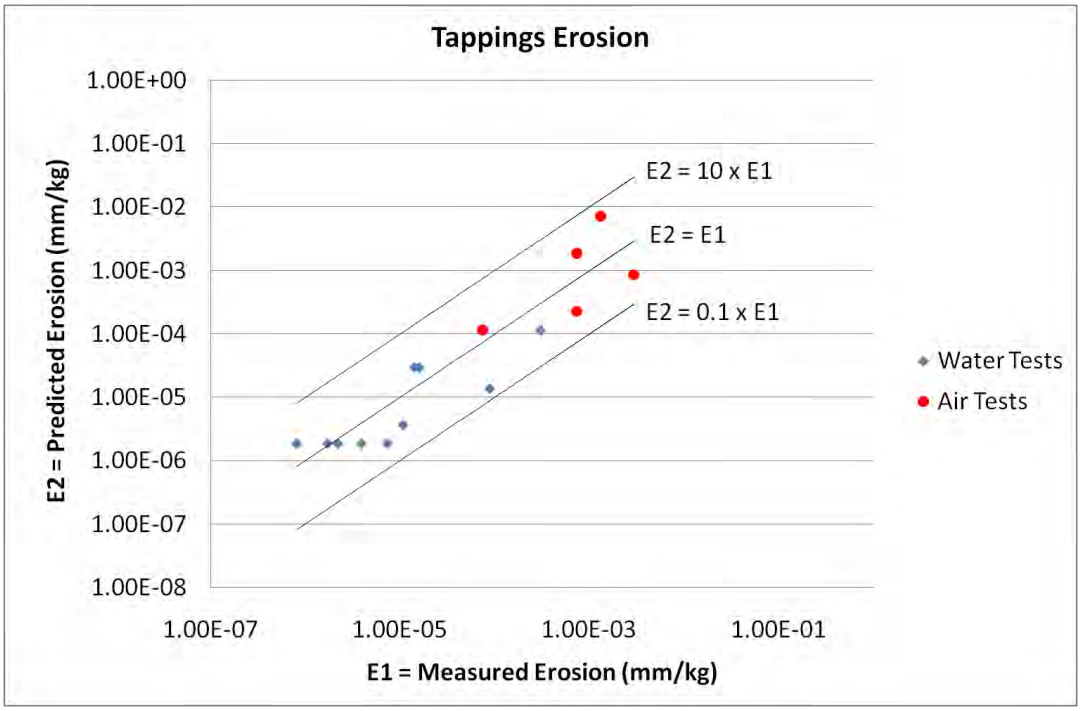

Figure 48. Comparison of measured erosion downstream of tapings with the predictions of equation 11

5.17 Assessment of Discharge Coefficient Shift

This section provides methods of estimating the effect of erosion on the accuracy of Venturi meters, cone meters and wedge meters. Note that all of the methods described in this section are based on limited test results. They may be applied to liquid, gas and multiphase flows over the full range of fluid densities and particles sizes likely to be encountered subsea. However, they are intended to provide an indication of the order of magnitude of metering error and they should be used with due caution.

Prediction of Discharge Coefficient Shift for Cone Meters

In the SwRI water/sand test 123,665 kg (274,810 lb) of sand caused a +10.77% shift in the discharge coefficient of the cone meter.

In the University of Tulsa air/sand tests 1350 kg (3000 lb) of sand caused a +25% shift in the discharge coefficient of the cone meter.

An equation has been developed for the cone meter which estimates the shift in discharge coefficient based on the assumption that most of the effect of erosion is caused by the change in throat area. It can be shown that:

$$\%\Delta C \cong \frac{A_{t0} - A_{te}}{A_{t0}}$$

Equation 12

Where:

%ΔC is the percentage shift in the discharge coefficient caused by sand erosion

A_{t0} is the throat area of a pristine meter (m^2)

A_{te} is the throat area of the eroded meter (m^2)

For a cone meter, as a first-order approximation, it has been assumed that the change in throat area is only caused by the increase in the pipe diameter as predicted by equation 7:

$$\%\Delta C = 100\left(\frac{4d_{pipe}(E_c/1000) + 4(E_c/1000)^2}{d_{pipe}^{\ 2} - d_{cone}^{\ 2}}\right)$$

Equation 13

Where:

%ΔC is the percentage shift in the discharge coefficient caused by sand erosion

E_c is the erosion scar depth on the pipe wall, as predicted by equation 7 (mm)

d_{pipe} is the pipe diameter (m)

d_{cone} is the cone diameter (m)

Figure 49 compares the measured error with predictions of equation 13.

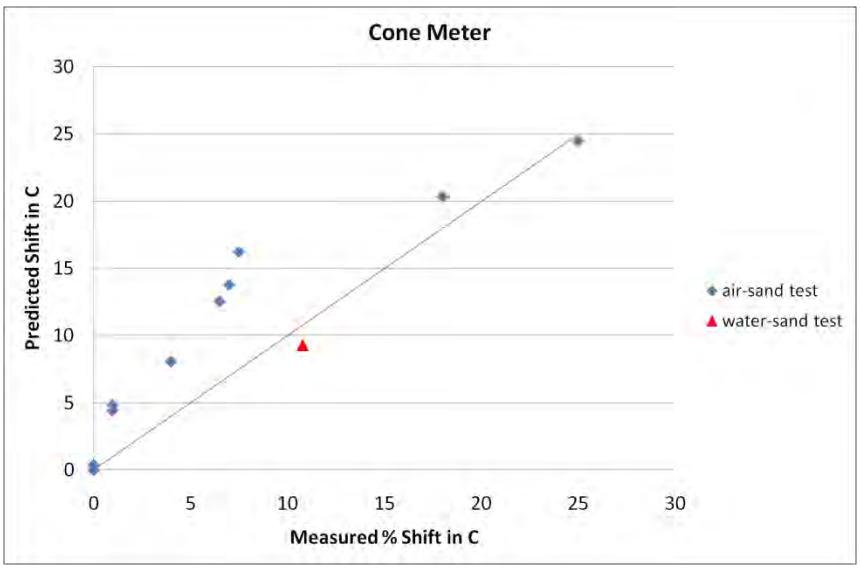

Figure 49. Comparison of measured and predicted shift in the discharge coefficient of a cone meter

Prediction of Discharge Coefficient Shift for Wedge Meters

Using a similar approach for the wedge meter as for the cone meter, it can be shown that the shift in discharge coefficient is approximately proportional to the erosion rate on the wedge and

wall surfaces at the throat. Equation 9 is used to predict an erosion scars on the walls next to the leading edge of the wedge. This scar will not cause much of a change in the discharge coefficient. However, it is reasonable to assume that the discharge coefficient will shift in proportion to the depth of this erosion scar as well. Thus the following equation has been developed:

$$\%\Delta C = 0.03432.\frac{(E_w/1000)}{d_{pipe}} \qquad \text{Equation 14}$$

Where:

%ΔC is the percentage shift in the discharge coefficient caused by sand erosion

E_w is the erosion scar depth on the pipe wall, as predicted by equation 9 (mm)

d_{pipe} is the pipe diameter (m)

Figure 50 compares the measured error with predictions of equation 14.

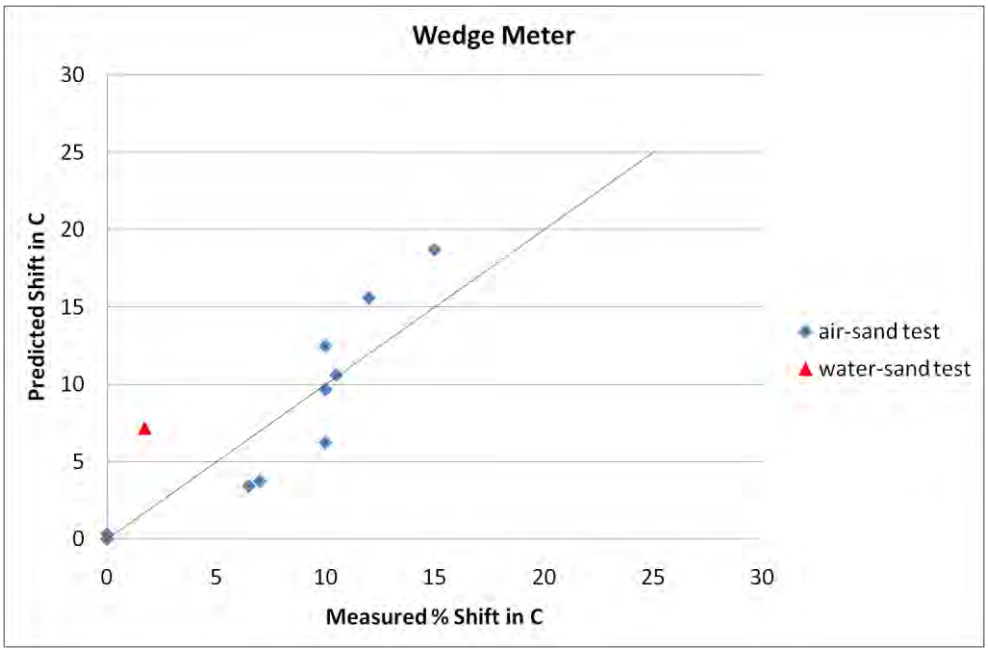

Figure 50. Comparison of measured and predicted shift in the discharge coefficient of a wedge meter

Assessment of Measurement Uncertainty in Venturi Meters

In the first SwRI sand-water test, 298800 kg (664000 lb) of sand caused a shift in the discharge coefficient of the Venturi of -1% for a mean pipe velocity of about 3.47 m/s. In the second SwRI test, 123665 kg (274,810 lb) of sand caused a -0.6% shift under nominally identical conditions.

In air-sand tests, the Venturi discharge coefficient initially increased by 6%, after 1000 lb (450 kg) of sand, before reducing almost back to its original value. Previous work has shown that

eroding the throat diameter causes an increase in the discharge coefficient and erosion of the tapings causes a decrease. This implies that throat erosion initially dominated in the air-sand test, and then tapping erosion started to balance this effect out after about 1000 lb (450 kg) of sand.

Given that both positive and negative effects can occur, and the limited amount of test data, developing an equation to estimate shifts in the discharge coefficient of a Venturi is challenging. In this case, it is assumed that the Venturi throat erosion equation (equation 5) gives an indication of the magnitude of the overall shift. However, as both positive and negative effects can occur, an equation has been developed to estimate the ***uncertainty*** in the measurement rather than the bias caused by erosion. Again, using a similar approach to that used for the cone meter the following equation has been developed:

$$u = 100\left(\frac{4(E_v/1000)^2 + 4(E_v/1000)d_{throat}}{d_{throat}^2}\right) \qquad \text{Equation 15}$$

Where

u is the standard percentage uncertainty associated with sand erosion

E_v is the throat erosion, as predicted by equation 1 (mm)

d_{throat} is the throat diameter (m)

Given the limitations of equation 5, this method is less reliable than those for the cone meter and the wedge meter. Ideally, the uncertainty defined by equation 15 should be greater than the magnitude of the shift in discharge coefficient. Figure 51 shows that this is the case for the water-sand tests. For the sand-air tests the uncertainty value is less than the measured shift for most of the data points. However, in general, equation 15 predicts the correct order of magnitude of the erosion effect.

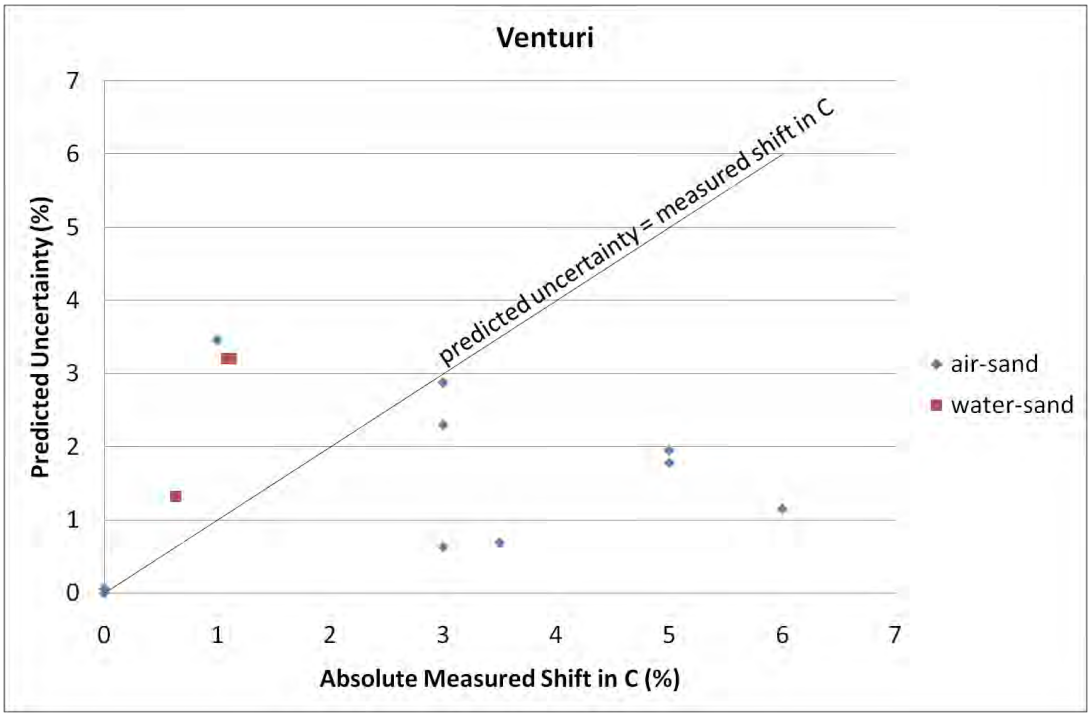

Figure 51. Comparison of uncertainty predicted by equation 15 with measured shifts in discharge coefficient for a Venturi meter

5.18 Application of the Prediction Method

An example calculation is included to show how the derived equations can be applied. Typical sand flow parameters are given as background information for those unfamiliar with sand and erosion assessment.

Typical Sand Flow Parameters

Typical sand rates used by various oil and gas operators for design purposes range from about 20,000 to 120,000 kg of sand per year for oil wells, which is roughly equal to between 1 and 40 pptb (pounds of sand per thousand barrels of oil).

Gas wells produce less sand with typical values ranging from 70 to 14,000 kg per year (~ 1 lb/mmscf).

Some operators define "sand free" conditions as 1 pptb for oil wells or 0.1 lb/mmscf for gas wells. Sand detectors do not produce good quantitative sand rate measurements, but they can typically detect about 1 g/s (1314 kg/year) of sand.

Sand size is typically 50 microns for a well with a fully functional sand screen. Otherwise sand sizes usually fall in the 150 to 300 microns range.

Example Calculation

This section gives an example calculation for the following conditions:

A wet gas flowmeter is to be installed in a 5-inch (OD) flow line 8 inches upstream of a 1.5D elbow. Two alternative designs of meter are available. The parameters of interest are as follows:

- Meter A – beta 0.5 Venturi, carbon steel body, wall thickness = 25.4 mm
- Meter B – beta 0.75 cone meter, carbon steel body, wall thickness = 25.4 mm
- Downstream elbow wall thickness = 25.4 mm
- It is not anticipated that the produced fluids will cause significant corrosion in the carbon steel components
- Gas density = 150 kg/m^3 at operational conditions and 0.7 kg/m^3 at standard conditions
- Water density = 1000 kg/m^3
- Oil density = 800 kg/m^3

Table 14. The estimated production profile for the example calculation

Year	Gas Rate	Water-Rate	Oil rate	Gas	Sand-Rate
2015-2020	50	1000	1000	150	2
2020-2030	20	1000	500	120	2
2030-2040	10	1000	0	100	2

Table 15 shows the results of the analysis for this example. These results indicate that the Venturi will erode at the throat, increasing the throat area by about 25% and that this will cause a significant flow measurement error. 78 mm of erosion is predicted downstream of the throat tapping. Note that this value is the length of the scar rather than its depth. This is much higher than anything seen in the tests. It exceeds the length of the throat and it is not clear what the shape or depth of the erosion scar would be. However, significant erosion damage is indicated. Intuitively, it seems unlikely that the negative effect of tapping erosion would compensate for the positive effect of throat erosion and it seems more likely that the eroded Venturi would under-read after 25 years of erosion.

Methods outlined in RPO501 predict 21.1 mm of erosion on the elbow approximately four diameters downstream of the Venturi. Considering the results shown in section 6.15, it would be expected that the Venturi would cause this elbow to erode faster than this (possibly ten or more times faster). Overall, it seems likely that the Venturi wall would not be penetrated but that the downstream elbow could fail.

Table 15. Example Calculation Results

Period		2015-2020	2020-2030	2030-2040
gas rate	mmscfd	50	20	10
water rate	bbl/day	1000	1000	1000
oil rate	bbl/day	1000	500	0
gas densiity	kg/m3	150	120	100
gas rate	kg/s	11.471	4.588	2.294
gas rate	m3/s	0.076	0.038	0.023
water rate	m3/s	0.00184	0.00184	0.00184
oil rate	m3/s	0.00184	0.00092	0
total rate	m3/s	0.080	0.041	0.025
mixture density	kg/m3	184.434	174.756	166.823
sand rate	lb/mmscf	2	2	2
sand rate	kg/year	16425	6570	3285
length of period	years	5	10	10
sand during period	kg	82125	65700	32850
Meter A (Venturi)				
D	m	0.077	0.077	0.077
d	m	0.0385	0.0385	0.0385
Vthroat (eqn 2)	m/s	68.851	35.216	21.287
throat erosion rate (eqn 1)	mm/year	0.789	0.055	0.007
throat tapping erosion (eqn 7)	mm/year	12.458	1.304	0.238
date		**2020**	**2030**	**2040**
cumulative throat erosion	mm	3.946	4.498	4.573
cumulative tapping erosion	mm	62.289	75.325	77.707
uncertainty (eqn 11)	%	45.196	52.192	53.150
Meter B (cone)				
D	m	0.077	0.077	0.077
d	m	0.051	0.051	0.051
Vthroat (eqn 2)	m/s	30.601	15.652	9.461
wall erosion (eqn 1)	mm/year	0.359	0.025	0.003
throat tapping erosion (eqn 7)	mm/year	9.228	0.966	0.176
date		**2020**	**2030**	**2040**
cumulative wall erosion	mm	1.797	2.048	2.082
cumulative tapping erosion	mm	46.141	55.798	57.562
shift in C (eqn 9)	%	16.981	19.420	19.750

Predictions for the cone meter show that, because it has a higher beta ratio, it will probably be more erosion-tolerant than the Venturi. Erosion at the wall downstream of the cone probably would not penetrate the wall and flow measurement errors are lower, although of a similar overall magnitude to those predicted for the Venturi. Section 6.15 indicates that erosion in the downstream elbow would probably be much less than for the Venturi. The primary cause for concern in this case is the downstream wall tapping. As deep erosion scars could occur in this location which could penetrate the wall.

It should be borne in mind that all of these prediction methods produce order-of-magnitude estimates only. Overall these results indicate that it is marginal as to whether erosion would

cause problems with either meter and that more detailed analysis would be warranted. This could include CFD analysis, testing and assessment of how realistic or conservative the assumed operating conditions are.

5.19 Summary of Erosion work

A large number of CFD simulations have been run to investigate sand erosion effects in Venturi, cone and wedge meters operating under conditions likely to be experienced in subsea metering installations. Equations have been developed which predict the pipe wall penetration rates and the effect of erosion on meter accuracy.

- The equations developed in this project are based on the results of the CFD simulations from this RPSEA study, data from previous air-sand and water-sand tests and the results of a previous CFD-based study into cone meters. They are intended to provide a first-pass, order of magnitude method for estimating erosion effects in subsea flowmeters and hence to indicate whether further testing or modeling of a specific installation is desirable.

  Particle erosion is a sensitive and potentially unstable process. Even the best-optimized erosion prediction methods do not predict erosion rates to a high level of accuracy. The prediction methods developed in this project are based on the best information available but they have only been validated in a very small number of tests. Due care must be taken and engineering judgment applied when using these methods. Specific information on the limitations of the prediction methods is given throughout this report.

- Overall there was a reasonably good agreement between the CFD simulations and the test data.
- Small beta ratio flow meters suffer more from erosion than larger beta meters.
- Small flow meters suffer more from erosion than larger meters.
- Flow meters are often placed close to downstream elbows, bends or similar fixtures in subsea installations. All types of differential pressure meters will act to accelerate erosion in downstream bends. This effect is particularly important in small beta flow meters. The erosion effect can be very large and may be the most probable failure mechanism in many installations.
- Erosion in the Venturi was not as easily characterized as that in the cone and wedge meters. This was because the CFD prediction method struggled to correctly predict erosion in the throat and tapings. Limitations of the air-sand test made the results for the Venturi less reliable than for the other two meters. Also the metering error depended on the complex interaction of the two counteracting effects of throat and tapping erosion. This further

complicated matters. As a result the prediction methods developed for the Venturi are less reliable than those developed for the other two meters. However, it should be noted that Venturis were less affected by erosion than the other two meters. Ideally, more work should be done to better characterize erosion in Venturis over a range of operating conditions.

On balance the Venturi meter would appear to be the most erosion-resistant design. This is partly because tapping erosion counteracts the effects of throat erosion and partly because the divergent section deflects particles away from the walls. Also, most erosion occurs in the Venturi throat, which is usually the thickest part of the pipe wall. This reduces the risk of pipe wall penetration. However, Venturi meters are often more damaging to downstream bends and this may be a severe limitation in some applications with a separation distance less than 5 D between the Venturi and elbow.

- As their throat is formed by a narrow annular gap between the cone and the pipe wall, a cone meter of a specific beta ratio will be more affected by erosion than an equivalent Venturi. The cone tends to direct sand to the walls and hence wall penetration and erosion of the downstream wall tapping (if there is one) are issues in this meter. However, high beta ratio meters will be significantly more erosion resistant than low beta meters and cone meters are usually less damaging to downstream bends than equivalent Venturi meters.
- Wedge meters are prone to wall penetration failure adjacent to the upstream edge of the downstream wedge. This tendency applies in high-pressure gas, wet gas, multiphase and liquid flows, but not in low-pressure dry gas conditions. The metering error of a wedge meter will be intermediate between a Venturi and cone meter of equivalent beta ratio. Wedge meters will accelerate erosion in downstream bends. In most cases, this effect will be smaller than for a Venturi. However, this will depend on the orientation of the bend, i.e. for a horizontal wedge vertical and horizontal downstream bends will erode in a different manner.
- Erosion effects are highly dependent on the operational parameters such as the flow rate, the liquid fraction, the sand rate and, to a lesser extent, the sand size.
- The CFD simulations indicated that the particle flow patterns in high-pressure gas flows resembled those in the liquid-sand tests. In this respect, it is believed that, although very valuable for validation purposes, the air-sand tests were not as representative of subsea conditions as the water-sand tests.
- The cone and wedge meters are mostly used for wet gas and are unlikely to see the severe water/sand erosion used in these comparative tests and simulations.

6. Results for Scale Deposition

6.1 General Information on Scale in Production Systems

This section gives an overview of scale formation in flow meters based upon a brief literature review, and informal discussions with TUV NEL personnel who have extensive experience with scale formation particularly in heat exchanger applications.

A large volume of information is available on scale formation, but it focuses more on the chemistry of scale formation and preventative measures rather than on scale distribution. Scale is usually a mineral compound. It can take the form of very thin films on fluid-wetted surfaces as well as significant accumulations that can block pipes and pressure taps. In many cases, scale is mixed with other substances such as iron or sand grains.

The most frequently encountered scale is calcium carbonate[5], caused by pressure release of water containing high bicarbonate concentrations. Other common scales are sulphates including barium sulphate, strontium sulphate and calcium sulphate. Sulphate scales are usually associated with the mixing of chemically incompatible waters (such as sea water and formation water).

The nature of scale(s) varies significantly from case to case. Some basic formation behaviors are known, although many scaling events involve combinations of phenomena[6] that make scale distribution inherently unpredictable.

Calcium carbonate scales are usually associated with low pressure regions and hot surfaces. Some salts precipitate out of solution below a threshold temperature, but inverse-solubility salts will precipitate out above a threshold temperature.

The formation of scale on a surface will alter the rate of heat transfer through the walls and can also affect further local scale formation. This effect is further complicated by the structure of

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[5] Personal communication with Dr Paul Ravenscroft, BP Exploration and Production Technology Group, Sunbury, UK, 29 March 2010.

[6] Bott, T.R., Fouling Notebook. Institution of Chemical Engineers, 1990, ISBN 0852952597.

the scale itself. The thermal conductivity of a scale layer will depend on whether it forms a solid or porous layer. An extreme example of this is seen in the graphite fouling that occurs on heat exchanger tubes downstream of combustion chambers and furnaces. Graphite scale is often highly porous. The graphite layer traps air and forms a highly effective thermal insulator despite the fact that solid graphite is, in itself, a highly heat conductive material. In multiphase flows this type of phenomenon will be less dramatic. But, as heat transfer rates are sensitive to velocity and thermal boundary layer behavior, porous and rough surface accretions can have significant effects on the local temperature.

Surface roughness can also be important. For example, scratches and rust spots may act as nucleation sites and the scale can grow out from that point. The additional surface roughness generated by the scale can then cause more scale to develop. Extra-smooth pipe wall surfaces have been used to reduce or prevent scale formation[7].

Barium sulphate scale, in particular, builds up by accretion of precipitated particles on upstream-facing surfaces.

Fluid velocity can have a major influence on scale formation. High chemical concentration gradients often drive scale formation. Increasing the flow velocity increases the velocity gradient in the boundary layer, and also increases concentration gradients between the surface and the fluid.

However, high fluid velocities also act to scour surfaces. Scouring tends to prevent precipitated particles from sticking to surfaces and breaks off (erodes) scale that has already grown on a surface. The removal of scale depends on the strength of the scale, and hence the history and nature of its formation. For example, if scale has formed over a rust spot because of high surface roughness, the rust layer may fail in shear by fluid scouring when scale formation has reached a critical thickness. Further scale growth may then depend upon the nature of the remaining surface scar and the state of the surrounding surface.

The fluid mass flow rate and the fluid's specific heat capacity affect the temperature of fluid-wetted surfaces. In high flow rate liquid flows the pipe wall temperature will be close to the fluid temperature. In low flow rate gas flows in subsea pipes without insulation, the pipe wall temperature approaches that of the sea temperature, particularly when strong sea currents

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[7] Bott, T.R. ibid.

convect heat away from the outside of the pipe. If the flow starts and stops, then the pipe walls are likely to be at the sea temperature periodically and this may be sufficient to initiate scaling.

There are currently no practical applied methods that predict scale distribution in pipe work components[8]. Many of the issues that make scale distribution difficult to predict also apply to wax formation. Attempts have been made to use CFD modeling methods to predict wax formation in production pipe work. However the variability of the adhesiveness and resistance to erosion of the wax build up has made it difficult (but not necessarily impossible) to match the observed and modeled distributions. Similar limitations will apply to scale formation predictions. Hence development of a CFD-based modeling method that can reliably predict the scale distribution for a particular set of circumstances is probably impractical. However, a more generic approach may yield useful information.

Scale in Flow Meters

Little information was identified on scale effects relating specifically to flow meters. The ASME wet-gas metering guideline[9] identifies a number of metering problems associated with scaling including blocking of transducer ports in ultrasonic meters, damaging of turbine bearings and changes to meter discharge coefficients.

The ASME guideline shows scale development on a wet-gas subsea cone meter. This meter was removed as part of an investigation into an increasing flow measurement imbalance between the subsea meter and meters further downstream. A significant build-up of material occurred on the meter walls. A pressure tapping was also blocked by the scale. The scale build-up was halted by using a scale inhibitor, but existing scale could not be removed without removing the meter from service.

Statoil experienced barium sulphate scaling on turbine meters on the Veslefrikk oil metering system[10]. Immediate remedial measures included the use of scale inhibitor, stripping and shot-

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[8] BOLT, T.R. ibid.

[9] The American Society of Mechanical Engineers. Wet Gas Flow Metering Guideline. MFC-19G – 2008.

[10] KLEPPE, K. and DANIELSEN, H.B. "*Scaling problems in oil metering system at the Veslefrikk Field*". North Sea Flow Measurement Workshop, 26 – 28 October 1993, Bergen.

blasting of the meters and regular recalibration. In the longer term, silver-plating and epoxy coatings were tried, but these tended to peel off or blister over time. The final solution was to polish the meters, tube bundles and other wetted components to a mirror finish.

BP experienced similar problems with zinc sulphide scaling, with possible additional sulphate scaling, in the Gyda oil turbine meters[11]. In this case, step changes were seen in the meter k factors, thought to be associated with scale building up and then falling off the meters' blades. Solutions included increased cleaning and calibration frequency and the use of scale inhibitors. Teflon coatings did reduce the rate of scale formation, but, as in the Veslefrikk case, some blistering was experienced.

There is one known case in which salts precipitated onto the upstream face of an orifice plate used for fiscal gas metering purposes. Significant work has been done on the effects of grease contamination on the front face of orifice plate through laboratory tests and CFD modeling[12]. In this case material on the front face effectively streamlines the meter, reducing the differential pressure and causing an under-measurement. CFD methods were found to model this effect accurately.

Most additional information is anecdotal. ConocoPhillips experienced scale on a Roxar multiphase flow meter in the Ekofisk field. This was associated with the mixing of produced waters from different sources. BP has seen calcium carbonate scales on Framo Venturis (in the

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[11] PAULSEN, F. & HANSEN, Ø. *"Scaling problems in oil metering system at the Gyda Field"*. North Sea Flow Measurement Workshop, 26 – 28 October 1993, Bergen.

[12] READER-HARRIS, M.J. & HODGES, D. *The effect of contaminated orifice plates on the discharge coefficient*. TUV NEL report 2008/266, September 2008.

[13] WILCOX, P. L. & BOSIO, J. *Sulphur deposition in sonic nozzles at K-Lab*, Report No 12, 1989

throat). In the 1980's, sulphur scale precipitation occurred in sonic nozzles in the K-Lab natural gas meter calibration facility causing a 2% error[13].

6.2 Experimental Study of Scale Deposition

The full report may be found at:
http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=611

The same three meters (Venturi, cone and wedge) that were used in the erosion testing were also used for this scale deposition testing. The experimental flow loop is shown in Figure 52.

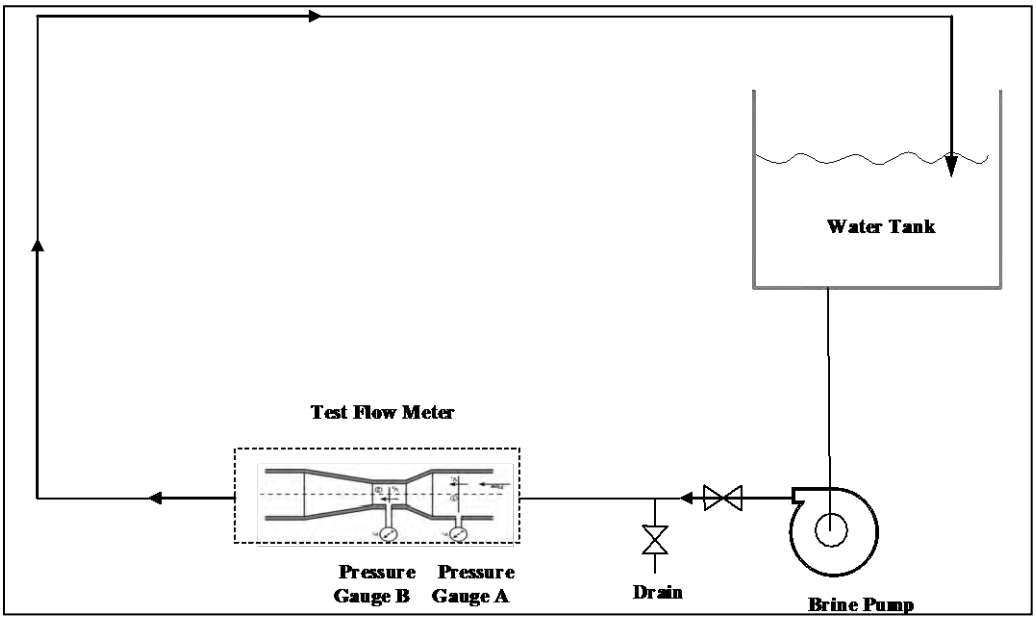


Figure 52. Schematic view of the scale deposition facility at Intertek.

The flow loop included a 200-gallon brine tank, a centrifugal brine pump, pressure and temperature sensors, and a computer based data acquisition system. The flow rate in the loop was controlled by adjusting the speed on the pump. Two inch diameter plastic pipe was used for connecting the system to limit scaling on the pipe walls, salinity loss and to maintain a constant flow. The test system was designed to handle a large amount of brine so that the temperature of the brine would not significantly change due to heat generated from the circulating pump and the composition of the brine would remain highly concentrated to facilitate scaling. No reference flow meters were installed in the flow loop, to eliminate scaling problems at these flow measurement devices. The brine flow rate was measured at the start and the end of the flow meter tests manually with a known volume container and a timer at the point where brine returned to the tank. The flow meters were installed horizontally in the test system. The entire

system was set up in an air-conditioned room. A thermocouple temperature sensor was mounted on the meter pipe wall to record the brine temperature.

Brine used in the tests

Synthetic heavy brine was used in the test. The starting brine concentration was measured after its preparation to ensure the correct concentration was achieved. The actual brine composition is listed in Table 16. The measured pH was 7 and the brine density was 1.1325 g/cm^3.

Table 16. Scale forming chemicals in the synthetic heavy brine

Cations	ppm (wt)
Calcium (Ca2+)	48000
Potassium (K+)	15000
Magnesium (Mg2+)	1500
Sodium (Na+)	60000
Anions	**ppm (wt)**
Chloride (Cl-)	195000
Bicarbonate (HCO3-)	3000
Sulfate (SO42-)	50

6.3 Scale Deposition Results for the Venturi meter

The flow rate was set at 11.1 gpm, corresponding to a velocity of 1.1 ft/s in the 2-in pipe. The average baseline pressure differential when the test started was approximately 9 cm WC. During the test, the tube that returned the brine to the tank was submerged to minimize salinity loss from brine splatters inside the tank. Because of this configuration change, the pressure differential had jumped from 11cm WC at the time to 16 cm WC. This 20% ($\sqrt{16/11}$) increase of flow was due the reduction in head (back pressure) on the pump. The average pressure differential was at approximately 23 cm WC when the test was ended as it was suspected that a significant amount of scaling had formed on the inside surface of the flow meter.

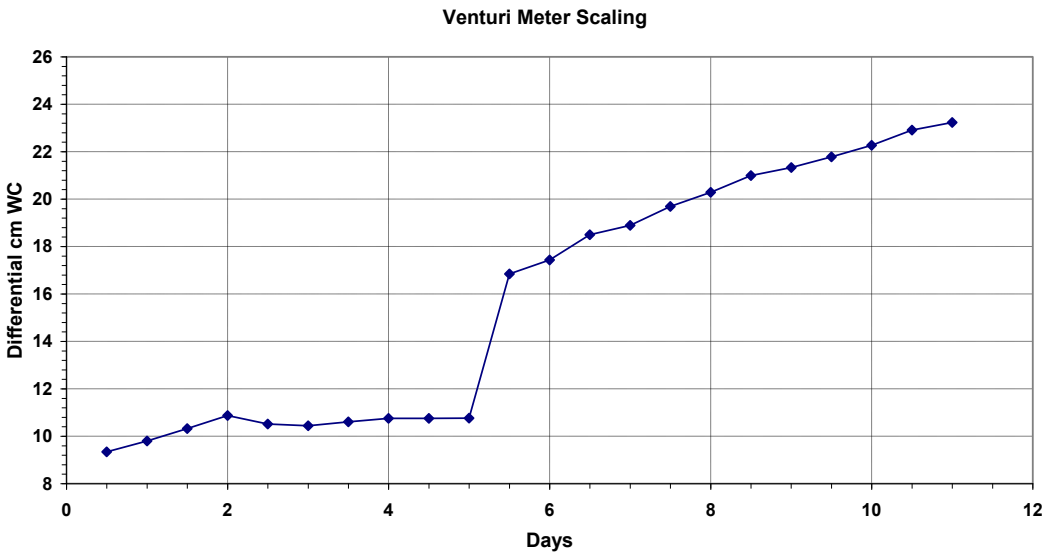


Figure 53. Pressure differential versus time for scale deposition tests

To calculate the discharge coefficient from the differential pressure, it was assumed that the discharge coefficient did not change across the jump from 11 to 16 cm WC. The starting value of $C_d = 0.97$ was based on the low Reynolds number of $1.4*10^4$. The change in C_d due to scale formation is about 20% based on the trend shown in Figure 54.

The Venturi meter was removed from the flow loop to allow for inspection for scale and corrosion. It was obvious to the observers that both had occurred during the test. Although the Venturi body was stainless steel, the flanges were carbon steel. Pictures were taken using a borescope of the Venturi meter scale and corrosion. The throat diameter of the Venturi flow meter was measured to be 25.8 mm before the test and 23.9 mm after the scale test. The scale was not deposited uniformly. The inlet cone was more scaled and the inlet flange was more corroded. Also, there appeared to be more scale deposition on the inlet cone than in the meter throat. Hence, the scale thickness at the throat (1.9mm) should be considered to be a rough estimate. Furthermore, the scale deposition was soft when wet, but flaky when dry. Scale deposition was not uniform across the meter, which made it very difficult to measure its thickness. See Figures 55 and 56.

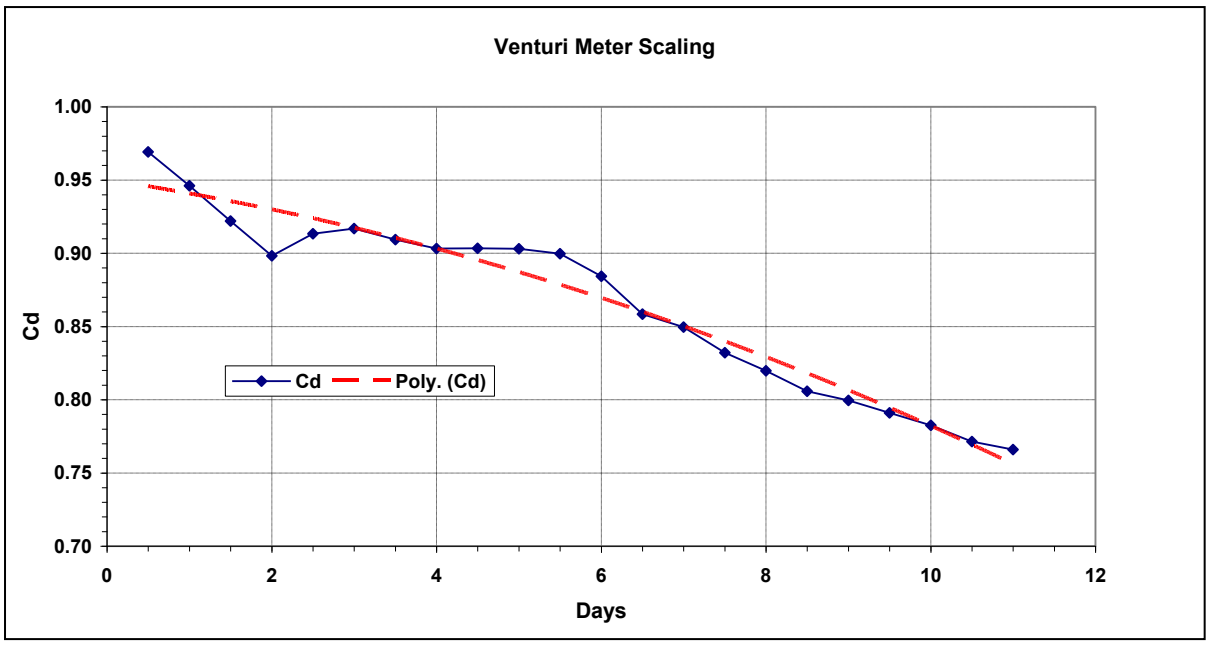


Figure 54. . Discharge coefficient change versus time for scale deposition tests

Figure 55. Venturi meter inlet CS flange wall after scale and corrosion

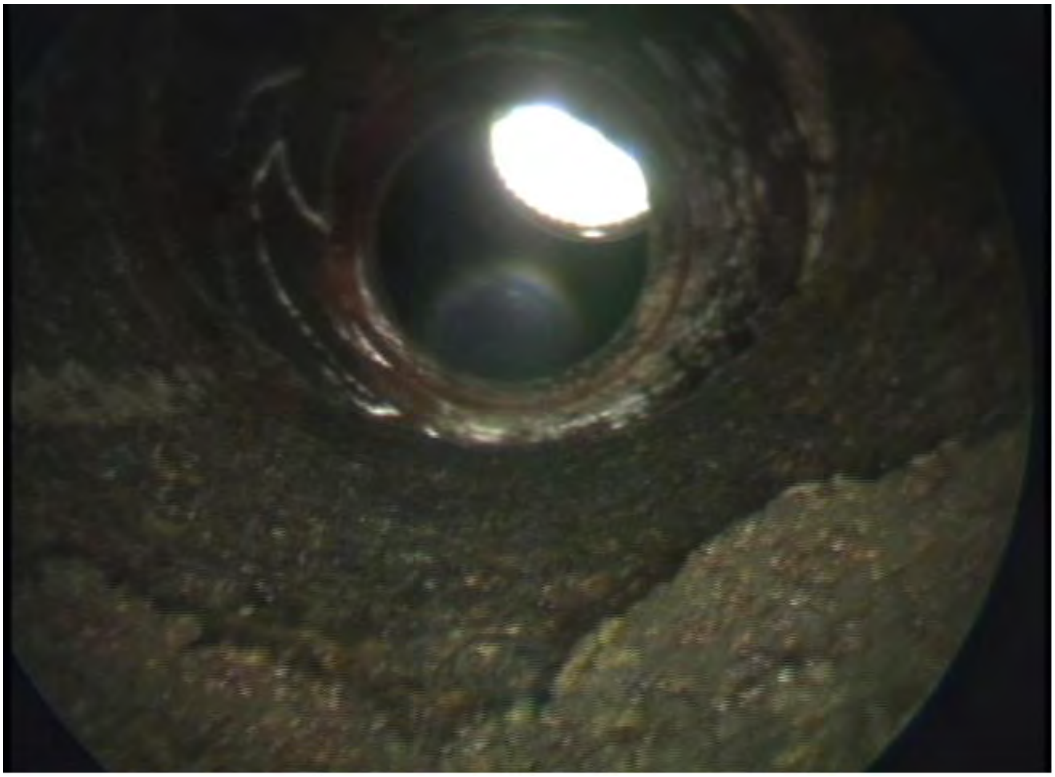


Figure 56. Venturi meter upstream cone and throat after scale deposition

The 1.9 mm scale thickness in the throat reduced the flow area by 16%, which would account for most of the 20% change in C_d. The corrosion that occurred on the CS flanges might have facilitated scale deposition.

6.4 Scale Deposition Results for the Cone meter

The cone meter was first tested at the same test conditions as the Venturi meter for performance comparison purposes. Brine at the same concentration was circulated at a flow rate of 11 gpm for more than 3 weeks with no scale build-up on the inside surface of the cone flow meter. The flow rate was then reduced to 7.5 gpm and the brine circulated for 2 more days with the pressure differential staying constant at about 6.7 cm WC. A fresh batch of brine with the same concentration was added into the system and circulated for two more days with no significant change of the 6.2 cm WC pressure differential. After this, the cone meter was subjected to cooling with the temperature reduced to 10 °F below room temperature for 5 days. The pressure differential then changed to about 8.6 cm WC (a 38% increase), which corresponds to a 17% decrease in C_d.

When the pressure differential stabilized, the cone meter was removed from the loop for scale inspection. Significant amount of scale had been deposited on the inside surface of the meter, especially upstream of the meter on the cone surface. The scale deposits looked thin and some

areas of the meter walls were barely covered. As with the Venturi meter, the scale formed was soft and non-uniform along the cone surface. It was difficult to measure the thickness of the scale deposition reliably and accurately.

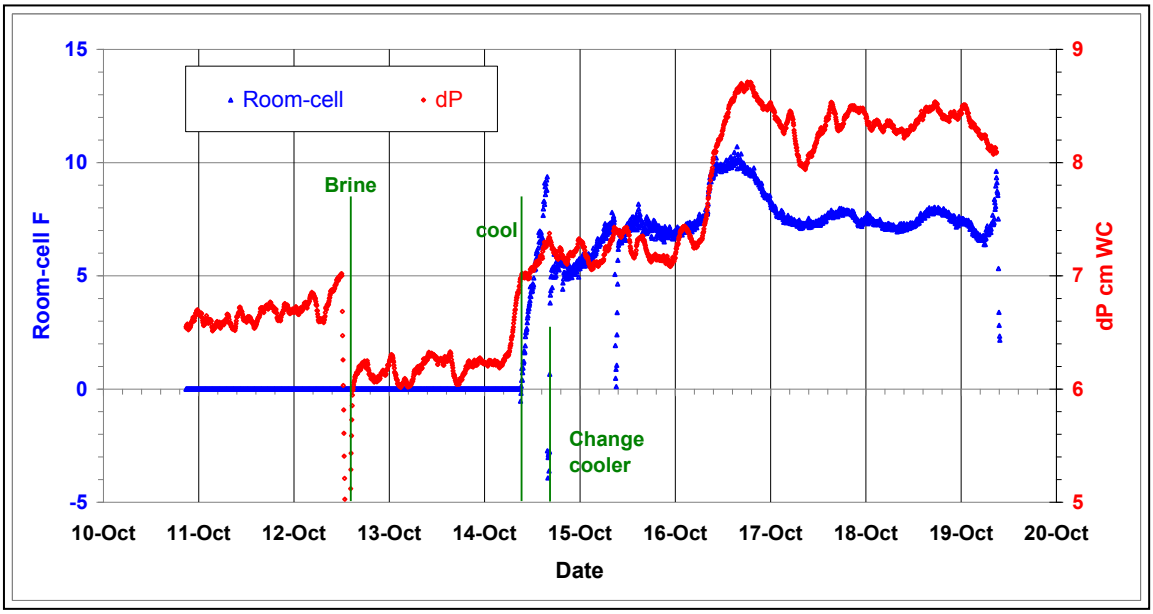


Figure 57. Cone meter scale test - pressure differential and temperature difference between room and meter

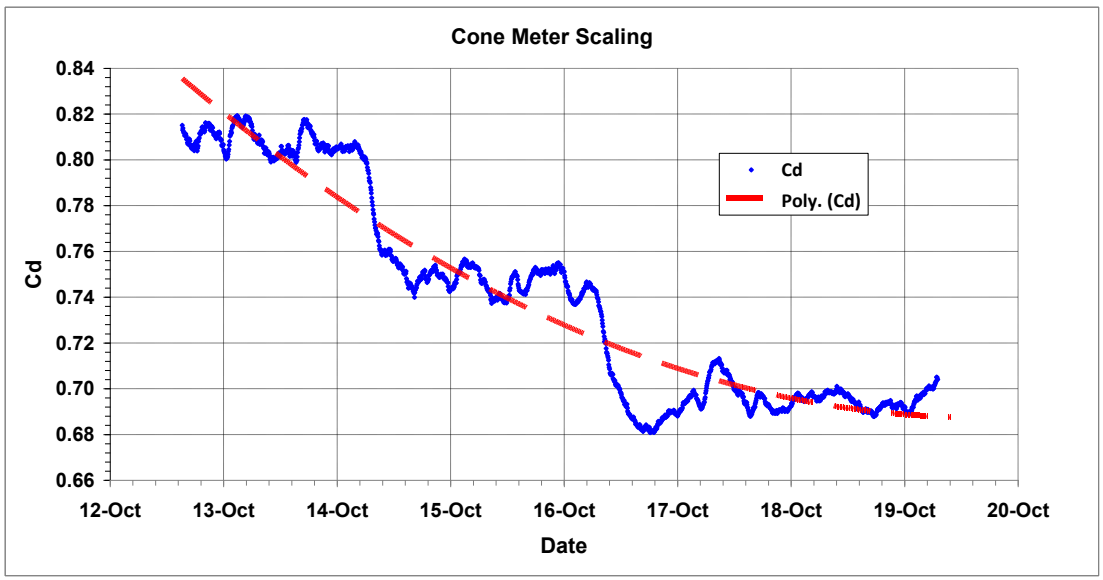


Figure 58. Discharge coefficient of the cone meter scale test

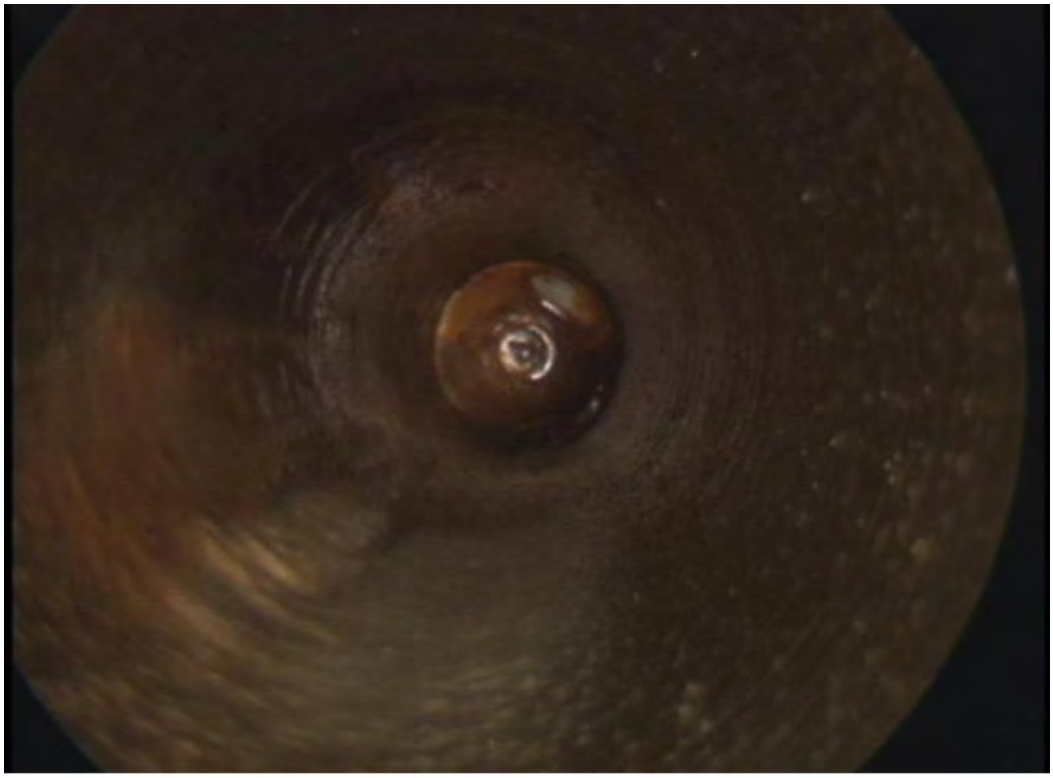


Figure 59. Cone meter looking from downstream at the cone, showing little scale build-up present

Compared to the Venturi and wedge meters, the cone meter was more resistant to scale deposition at the test conditions. This could have been due to the lack of corrosion in the cone meter, but there was no corrosion in the wedge meter either. Perhaps the high shear of the flowing fluid in the narrow annulus of the cone meter discouraged scale deposition.

6.5 Scale Deposition Results for the Wedge meter

The wedge meter had a 1.689 in internal pipe diameter (2-in schedule 160). It was made of stainless steel material and the inside surface was rougher when compared to the Venturi and cone meter tested. The increased surface roughness may be a result of the spark erosion fabrication method of the wedge meter. The PVC tubing of the test rig was replaced with 1.5 inch diameter PVC pipe to better match the wedge meter pipe size.

The same concentration of brine was circulated with a flow rate of 11 gpm while the wedge meter was cooled and heated a couple of times to induce scale deposition on the meter surface. The test lasted for 6 days until the pressure differential was almost zero. The wedge meter was removed from the test rig and inspected for scale. It was observed that heavy scale had built up on the inner surface of the meter, and that the pressure taps were blocked with scale.

The pressure readings from the taps were meaningless because of tap blockage. So, the wedge meter's performance change before and after scaling were measured with the scaled meter (and unblocked pressure taps) and a new un-scaled wedge meter. A flow rate of 8 gpm was used to avoid the risk of scale removal by the flowing brine. No apparent scale/solids were observed when the flow was re-started. The pressure differential of the un-scaled (new) wedge meter at 8 gpm flow was found to be approximately 4 cm WC. In comparison, the scaled wedge meter pressure differential was about 7.5 cm WC. The amount of scale build-up on the inside surface of the wedge meter had caused the pressure differential to increase by about 87% in 6 days at the test conditions, corresponding a 37% reduction in C_d.

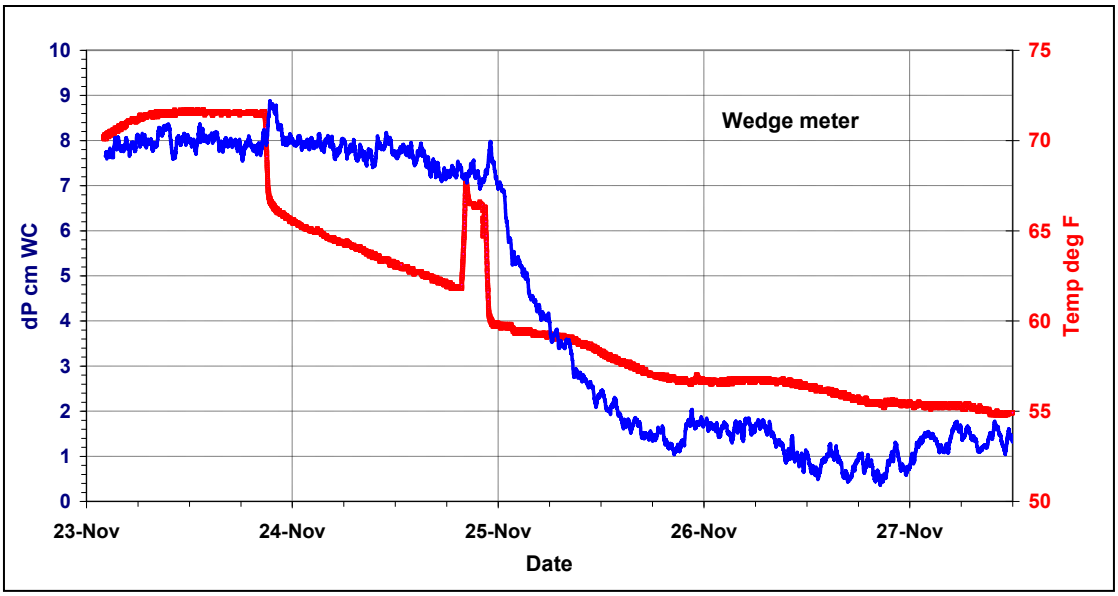


Figure 60. Wedge meter pressure differential (dP) and temperature (T)

The scale deposition on the wedge meter appeared to be more crystalline and thicker than that on the cone meter. No sign of corrosion was observed. It is difficult to compare the scale deposition on the wedge meter with that on the Venturi or cone meter as they were apparently different kinds of scale.

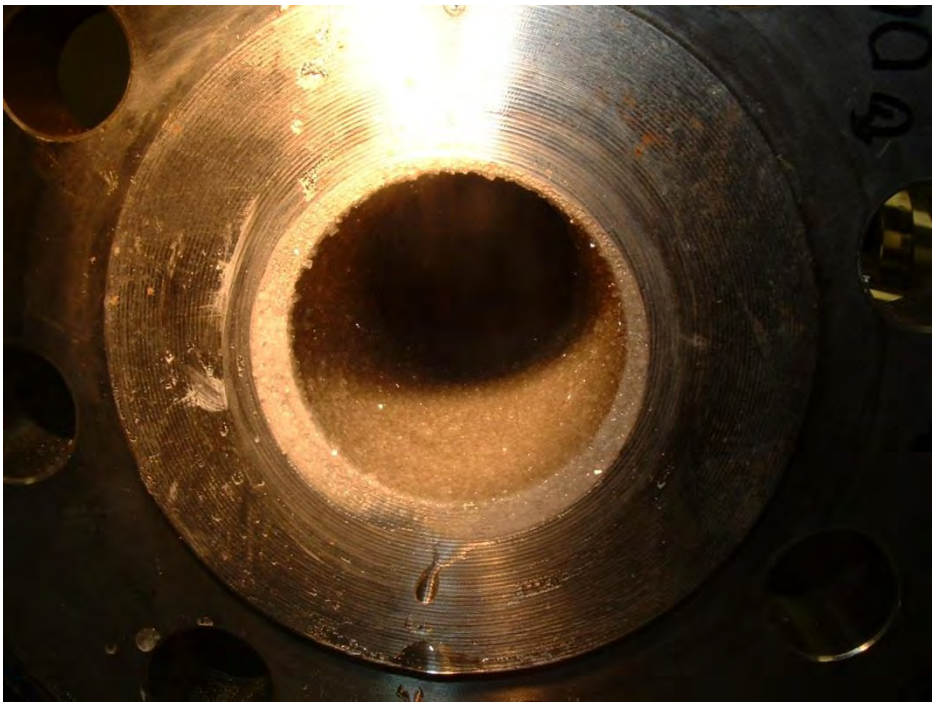
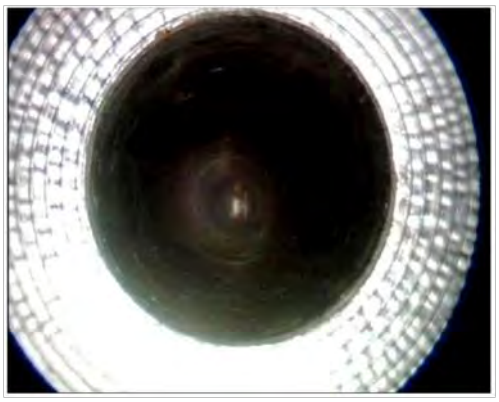


Figure 61. Wedge meter crystalline scale



Clean Tap

Scale-Blocked Tap

Figure 62. Photographs of the wedge meter pressure taps

The wedge meter taps are made from a 6-in length of ½-in Schedule 160 pipe, welded to the body at one end and to a ½-in 300# flange (see above) at the other. The pipe ID is 12 mm and a

4 mm hole is drilled through the meter body wall to make the fluid connection. The small point of light visible in the center of the clean tap photograph is the 4 mm tap hole. There is a large reservoir of brine and a small hole to block.

6.6 Scale Deposition Experimental Results Summary

For each flow meter, one hundred gallons of synthetic heavy brine was circulated for periods ranging from days to weeks until the pressure differential between the two tap points changed enough to indicate that significant scale had been deposited on the inside surface of the flow meters and that the flow meter's performance had been altered. Significant amounts of both corrosion and scaling occurred during the Venturi meter test period. The corrosion is mainly due to carbon steel flanges on the stainless steel body. The scaling produced a C_d change of 20%.

For the cone meter, the brine was circulated at the same conditions as the Venturi meter for approximately two to three weeks. Little scale build up was observed. The cone meter was then subjected to cooling conditions and a reduced flow rate to speed up the scaling process. The test was completed in approximately four weeks: scaling produced a C_d change of 17%.

The same brine conditions and similar temperature settings were applied to the wedge meter. Significant scale accumulation quickly altered the meter's performance due to pressure tap blockage. The flow performance before and after scaling was tested with a clean wedge meter and the scaled wedge meter (with cleared pressure taps) at the same flow. Scaling produced a C_d change of 37%.

The scale deposition tests have demonstrated quantitatively that scale can severely affect the performance of all three kinds of flow meter tested on this RPSEA JIP. At this early phase of the study, the tests were not designed to be carried out under realistic field conditions:

- Meters were not subjected to multiphase flow.
- High pressure - high temperature subsea conditions were not applied.
- The test flow rate was low (typical velocity 1 ft/s) to facilitate scaling.
- Cooling was also used to facilitate scaling.

Therefore extrapolation of these test results to real field flow meter performance may not be appropriate.

Under the described test conditions, it appeared that the cone meter is the most resistant to scale, and the wedge meter the least resistant. However, these results for flow meter

performance may be a result of varying the material, the surface quality and the test conditions. The test program varied:

- Material (carbon and stainless steel)
- Surface roughness (due to fabrication methods)
- Meter schedule and beta ratio
- Brine flow rates
- External heating and cooling.

The conclusions of these tests may not be valid under other conditions.

The difficulty encountered in producing realistic scale in the laboratory led to the idea of using CFD to simulate the effects of scale deposition on meter performance.

6.7 Flow Meter CFD Scaling Analysis Results

The full report may be found at:
http://www.rpsea.letton-hall.com/tiki-download_file.php?fileId=612

All of the information gathered on scaling suggests that it is ***a highly complex and variable process that is difficult to predict***. However, there may be basic rules of thumb that can be used in meter design and selection to minimize the impact of scaling on meter accuracy, should scaling occur in the field. Many of the factors controlling scaling are associated with fluid chemistry, the history of the meter and other similar factors that are beyond the scope of this study (and probably cannot be considered in a generic manner). However, the fluid flow behavior in a differential pressure meter and how the flow behavior may affect scaling and meter accuracy can be assessed. This involves using theoretical and CFD methods to compare different meter designs. The goal is to identify design features that may be desirable if scale formation is a possibility.

Scale affects the accuracy of differential pressure meters by increasing the effective surface roughness, by blocking the pressure tapings, and by reducing the flow area. Figure 63 classifies degrees of scaling on the walls of a cone, Venturi and wedge meter. Regions where scale is deposited are shown in green. When the meters are clean it can be assumed that they will all operate correctly and that there is no particular advantage of one type of meter over another from a scaling point-of-view.

It is conceivable that scale could form to selectively cover the internal surfaces of the meter. This may be because of the condition of or the fabrication quality of the surfaces. This case does

not lend itself to prediction as scratches, rust patches and surface finishes vary from case to case. However, if the distribution of scale is known then a comment can be made on how badly a particular meter will be affected.

Partial scaling may also be controlled by flow-related phenomena, such as scouring. In this scenario it is possible that one type of meter may have a specific advantage. For example, it may tend to clean itself in critical locations.

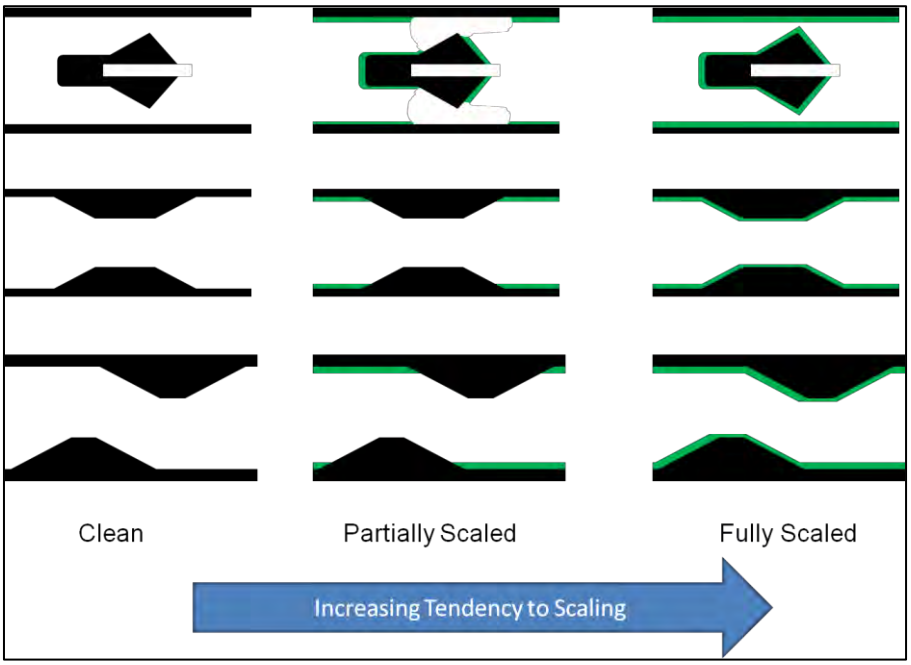


Figure 63. Classification of degrees of scaling in a cone, Venturi and wedge flow meter

6.8 Flow Meter Fully Scaled Analysis

The fully-scaled scenario assumes that there is an even, smooth growth of scale on all wetted surfaces, as shown above. The calculated effect of this type of scale growth on 2-inch Venturi and cone meters is based on a simple theoretical analysis. It is assumed that the cone, throat and pipe diameter are reduced by the scale thickness and hence an effective beta value and discharge coefficient can be calculated. The difference between the effective discharge coefficient and the clean discharge coefficient is used to calculate the shift in discharge coefficient.

To allow like-for-like comparison, equivalent beta values are used for the cone meter to allow for differences in discharge coefficients. A cone meter with an equivalent beta value of 0.6 will produce the same pressure differential as a beta = 0.6 Venturi operating at the same mass flow

rate. True cone beta values refer to the beta value defined as standard by cone manufacturers. Hence cone beta ratios of 0.411, 0.645, 0.740 and 0.822 are used as equivalent to Venturi beta ratios of 0.4, 0.6, 0.68 and 0.75 in this report.

Note that this analysis assumes that tapings remain unblocked and unaffected by scale.

A 0.5 mm uniform thickness of scale inside a 2 inch beta 0.4 cone causes a -21% shift in the discharge coefficient and a -10% shift in an equivalent Venturi. Cone meters with larger beta values suffer less from scaling than smaller beta meters because a given scale thickness produces a smaller percentage change in the throat area. Similarly, Venturi meters suffer less than equivalent cone meters because a given scale thickness causes a smaller change in throat area.

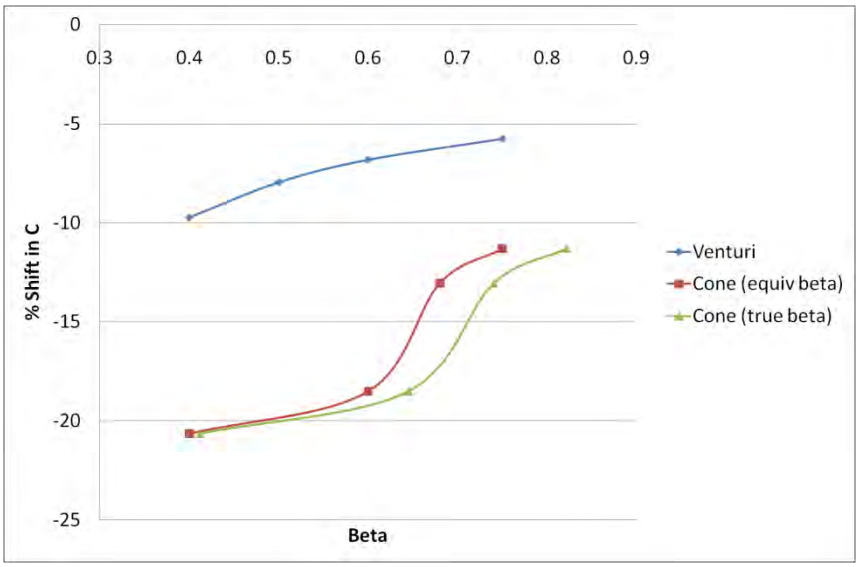


Figure 64. Theoretical effect of an even, smooth 0.5 mm scale layer on the discharge coefficient of 50.8 mm (2-inch) meters

The calculations were repeated changing only the Venturi throat or the cone diameter while keeping the pipe diameter constant. Figure 65 shows that for a Venturi, nearly all of the effect of scaling is caused by a reduction in the throat diameter. In a cone meter, about half of the effect is caused by the accumulation of scale material on the cone and the other half by scale material collected on the pipe wall.

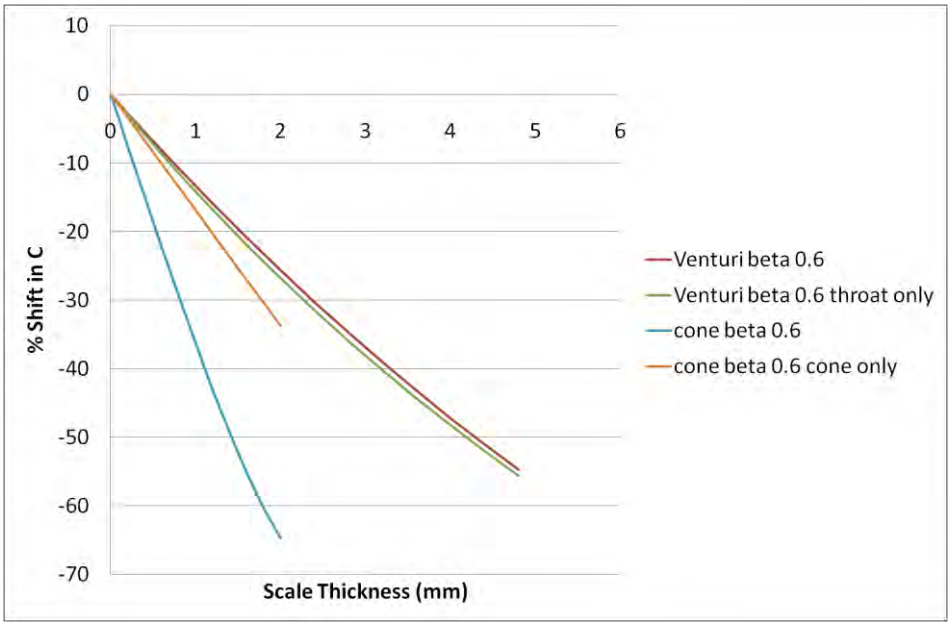


Figure 65. Comparison of the effect of reducing both the pipe and throat diameters with reducing only the throat diameter for a beta 0.6, 2-inch meter

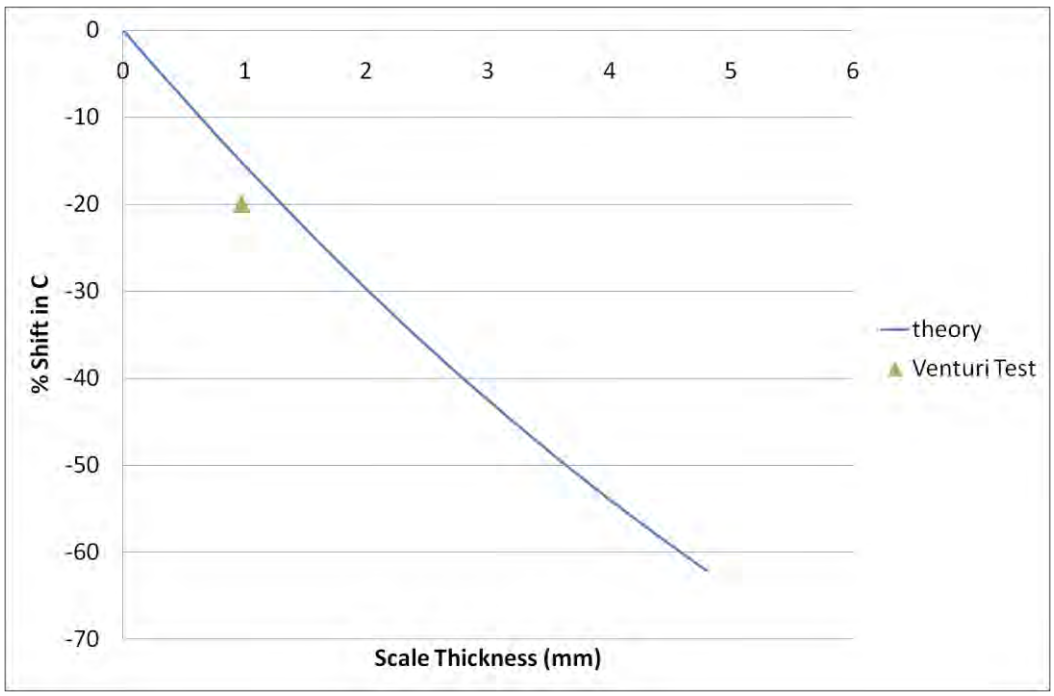


Figure 66. Comparison of the theoretical analysis with test results for the Venturi

Figure 66 compares the results of the Intertek scaling tests with the theoretical analysis. The Intertek report stated that the throat diameter was reduced by approximately 1.95 mm (i.e. that the scale thickness in the throat was 0.975 mm). This resulted in a -20% shift in discharge

coefficient. It can be seen that the measured effect agrees closely with the theoretically derived value.

Figure 67 compares the CFD predictions for a uniform, smooth scale build-up with the calculations based on beta changes. It can be seen that the CFD predictions compare very closely with the theoretical calculations for the Venturi and cone meters. The wedge meter results fall between the beta = 0.6 and beta = 0.75 Venturi results. The Venturi and cone meters are axially-symmetric, allowing the beta to be changed. However, the wedge meter is 3-dimensional, with the wedges reaching the centerline. This makes the area ratio 0.5 and beta = $\sqrt{0.5}$ = 0.707. This design does not allow changes in beta.

The Venturi and cone are "Bernoulli devices", with the area reduction in the throat producing a high velocity that is the major contributor to differential pressure. The wedge meter does not have a single, obvious throat and the low pressure is not measured at a throat. The wedge meter is a distributed resistance device where the total pressure loss is measured end to end from inlet to outlet. The wedge was originally designed to have a very different wet gas response (over reading as a function of liquid loading) to a Venturi. Both types of meters are used in series in a Dual-stream ISA wet gas flow meter.

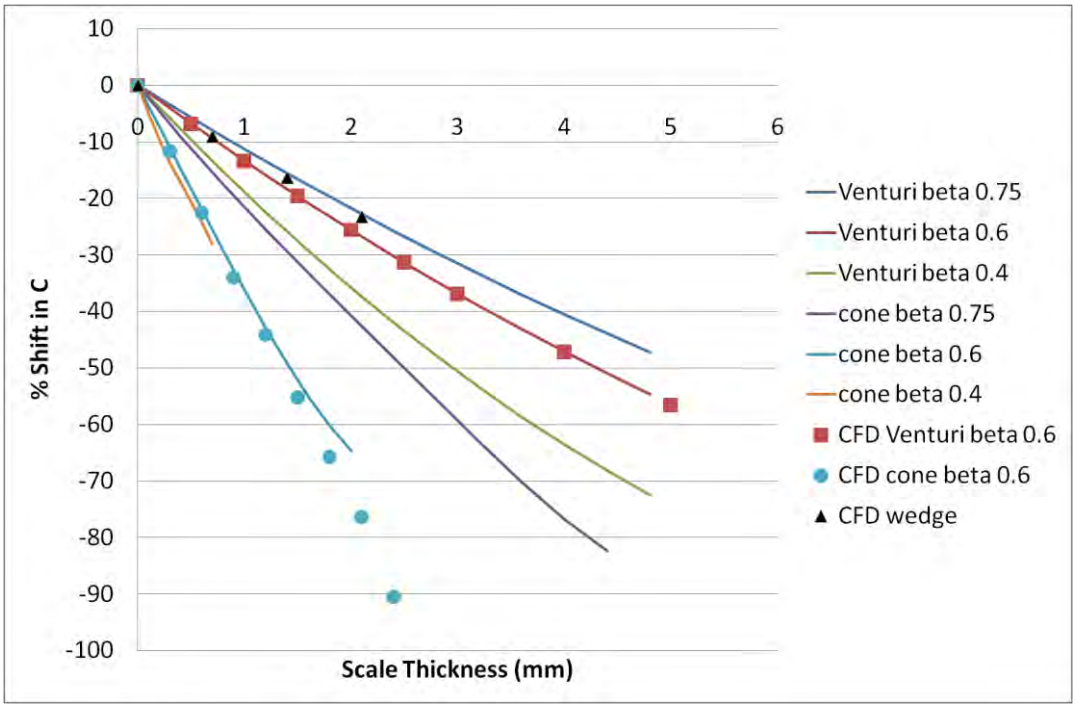


Figure 67. CFD predictions assuming a uniform, smooth scale layer and a comparable effect calculated theoretically

6.9 Flow Meter Fully Rough CFD Analysis

CFD computations were performed to simulate water flow through a 2-inch beta = 0.5 Venturi meter, a beta = 0.5424 cone meter and a wedge meter (with an effective beta ratio of 0.707 and a pipe ID of 50.8 mm) having rough internal surfaces. The aim of this work was to identify which surfaces of the meters are most sensitive to scale build-up. This information may also be helpful in interpreting the effect on measurement accuracy that scale may have had where a blocked meter was inspected and the scale distribution was documented.

As in the previous analyses, it is assumed that pressure tapings are unaffected by scale.

Figure 68 shows the effect of varying the roughness of all the wetted surfaces for the three meters, including the upstream pipe, assumed to be infinitely long. (This assumption is made to remove any effects of developing upstream velocity profile). In these computations, the effect of surface roughness is simulated by changing the velocity gradient within the boundary layer. This is equivalent to adding very small amounts of material onto the clean walls (i.e. accretion of material rather than erosion of the walls).

In all cases, surface roughness results in negative shift in the discharge coefficient (i.e. an over-reading). Even very small increases in surface roughness can result in significant error. For example, a roughness height of 0.1 mm causes a shift of -5% in the wedge meter.

The cone meter is the least sensitive to surface roughness effects and the wedge meter is the most sensitive. One reason that the wedge is more sensitive is that its tappings are further apart and hence pressure losses through wall friction will be larger. Also, the wedge has a higher effective beta value of about 0.707 and hence a smaller total pressure differential. The wall-friction element will therefore form a greater fraction of the overall pressure differential and hence the wedge meter is more sensitive to wall friction.

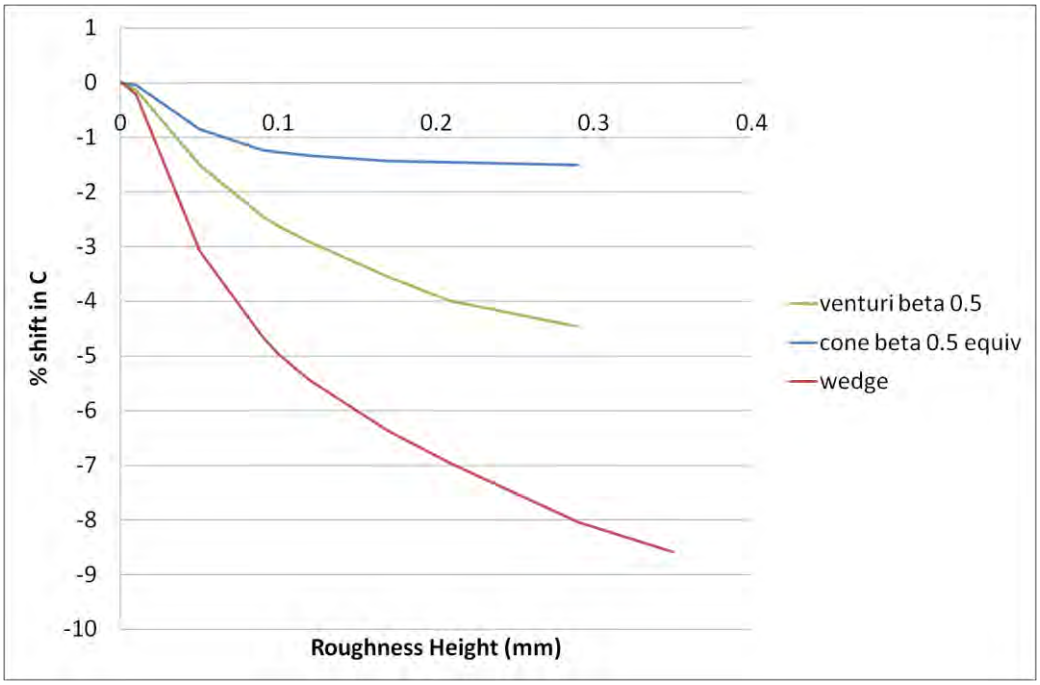


Figure 68. Effect of uniformly distributed roughness on all of the walls of a 2-inch Venturi, cone and wedge meter

Note that the wall roughness heights modeled are small in comparison with the size of scale blockages used in previous simulations. If scale with a rough surface grew to cause a significant blockage in the throat area, then it would be expected that the blockage effect would dominate over the wall roughness effect. The cone meter would then show a larger shift than the Venturi and wedge meters.

6.10 Flow Meter CFD – Artificial Blockages

Here is an example of the effect of adding material to the upstream face of the cone meter's cone. Figure 69 shows that setting angle A1 to zero represents a very large scale build up on the cone. Considering the degree of scaling this represents, it can be said that the cone meter is relatively insensitive to scaling on these surfaces.

Interestingly, scale on the upstream face of the cone causes a positive shift in discharge coefficient. This is because the scale reduces the angle of the cone at its maximum diameter, which allows the "vena contracta" to enlarge, and reduces the pressure differential across the meter.

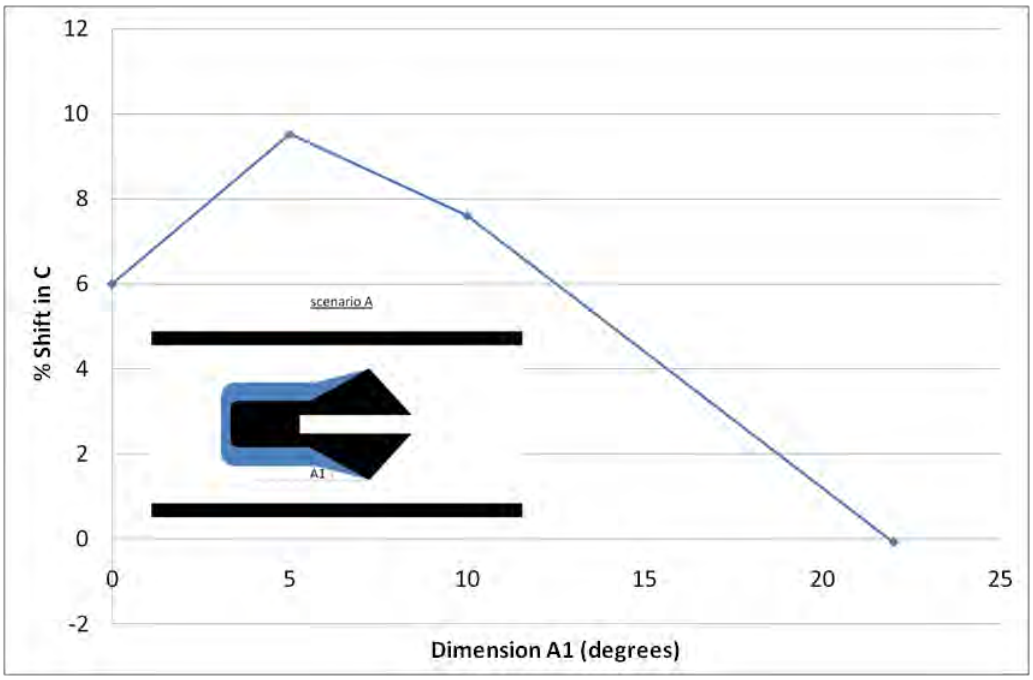


Figure 69. Effect of material build–up on the upstream face of a beta = 0.5424, 2-inch cone (when A1 = 22.5o meter is clean)

Figure 70 shows that accumulation of scale on the back face of the cone also causes a much larger, positive shift in the discharge coefficient. Again, the scale alters the size of the "vena contracta", in this case by acting as a diffuser, similar to the divergent section of a Venturi. This promotes pressure recovery and reduces the overall pressure differential. This effect is strongest when the B1 angle is small, about 9°, and the flow remains attached to the scale surface.

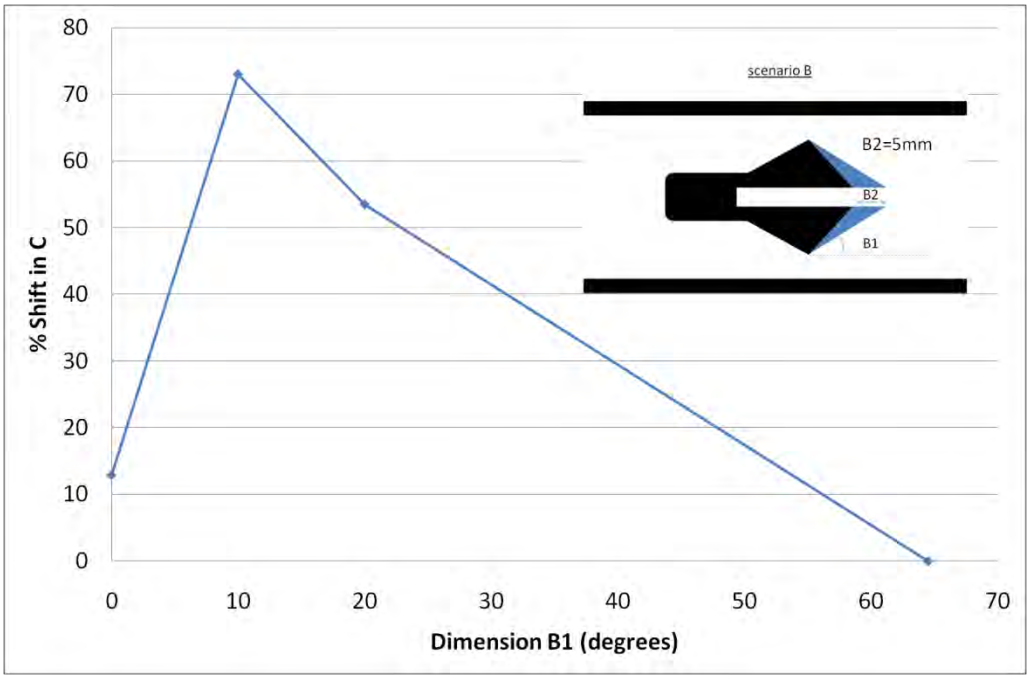


Figure 70. Effect of material build–up on the downstream face of a beta = 0.5424, 2-inch cone (when B1 = 65o meter is clean)

As another example, Figure 71 shows the effect of material accumulation in the convergent section of a beta = 0.5 Venturi. CFD analysis of blockage in the upstream and downstream sections has very little effect until it is in the throat. When the blockage is downstream of the throat tapping, it forms a high-pressure stagnation zone that raises the pressure at the throat tapping, thus reducing the measured differential pressure. However, this effect is very small compared with others modeled in this exercise.

However, Figure 71 shows that when the blockage approaches the throat on the upstream side, the blockage becomes the minimum flow area, reducing the throat size and increasing the differential pressure. This produces a large negative shift in the discharge coefficient.

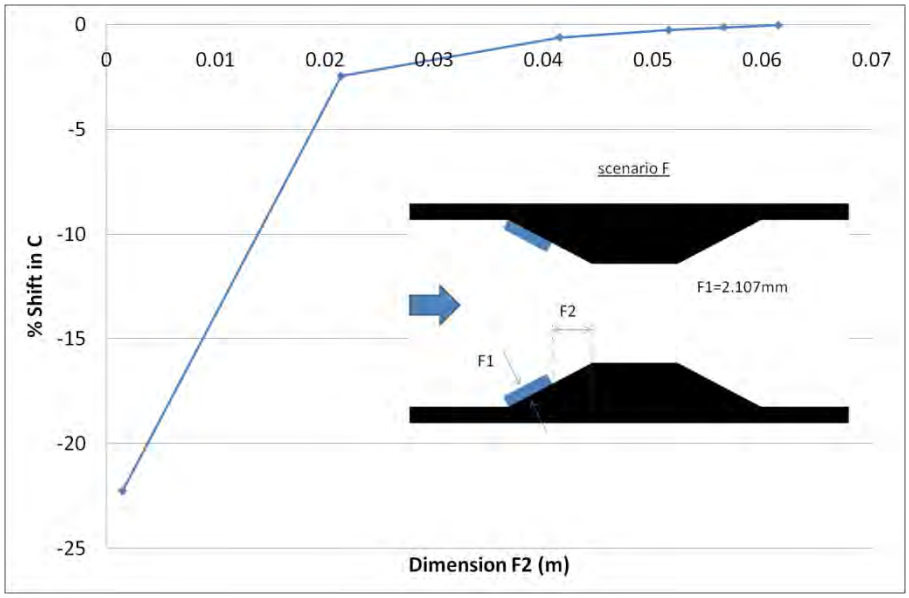


Figure 71. Effect of material build–up on the convergent section of.

6.11 CFD – Simulated Scour-Sensitive Scale Growth

Scale formation is often controlled by the shear forces exerted by the flowing fluid on fluid wetted walls. If the wall shear stress is high, then the walls are scoured by the fluid flow and any scale that forms on the wall may be removed again quickly. It is reasonable to expect that scale forms only in locations where fluid scouring is minimal. This appears to be the case in the Intertek tests of the cone meter where little scale was seen on the pipe walls immediately downstream of the cone.

Figure 72a shows typical predictions of wall shear stress in the Venturi and cone meters, and Figure 72b shows predictions of wall shear stress in the wedge meter operating under identical conditions.

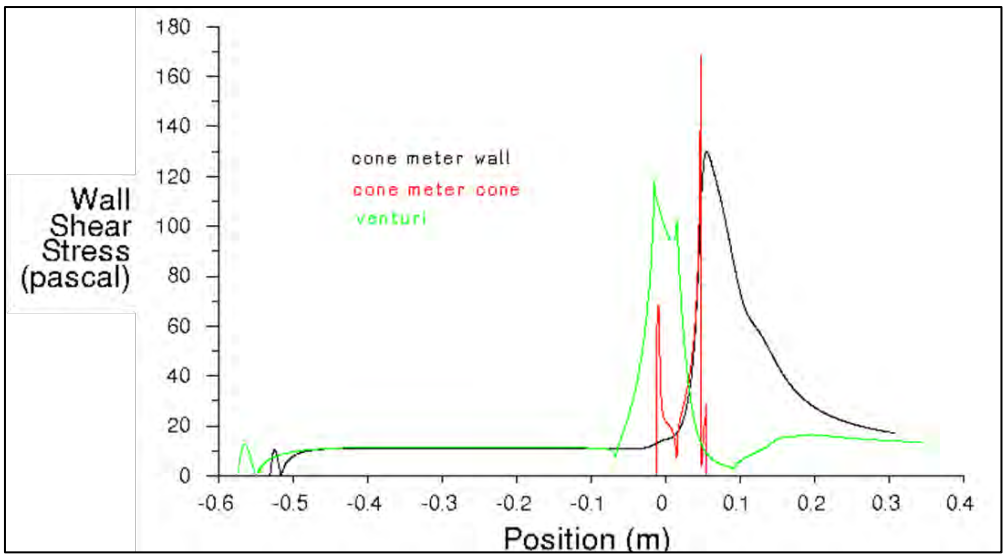


Figure 72a. Variation of wall shear stress (Pa) on a clean beta = 0.6 Venturi, and a beta = 0.6 equivalent cone meter

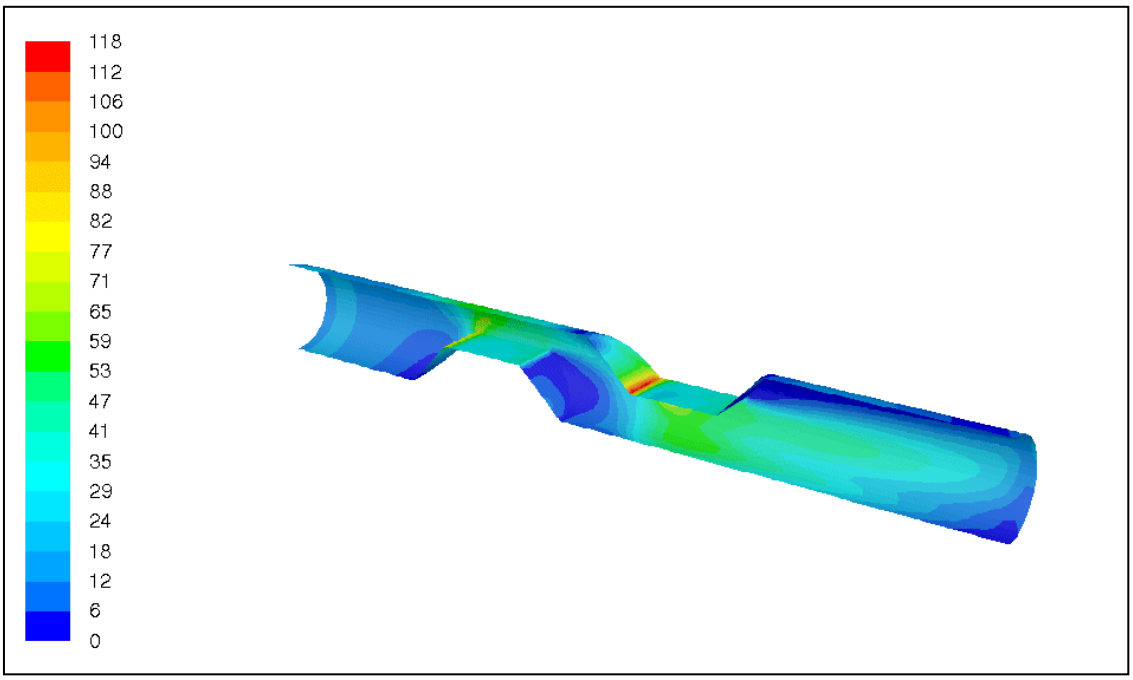


Figure 72b. Variation of wall shear stress (Pa) on a clean beta = 0.707 wedge meter

The next set of figures show the predicted response to a scour-sensitive scaling scenario. Scale scouring causes a negative shift in discharge coefficient of a similar order of magnitude to the shifts seen in the tests.

Figure 73 shows the response of a beta = 0.6 Venturi to scale with different wall shear-stress thresholds. When the threshold is set to 300 Pa, an almost uniform scale distribution occurs resulting in the negative discharge coefficient shift previously seen for smooth uniform scaling.

As the wall shear stress threshold is reduced, the shift becomes more erratic because the model produces scale with a stepped shape. This causes local high-pressure and low-pressure zones that can have a major effect, particularly when they are near the throat tapping. A wall shear stress threshold of 50 Pa has little effect on the Venturi discharge coefficient.

Figure 74 shows that the cone meter is predicted to be significantly more sensitive to scale scouring under equivalent conditions. As with the Venturi, the cone meter response approaches that of the smooth even distribution as the shear stress threshold increases. Figure 74 also shows scale scouring results for the wedge meter. The wedge meter produces an intermediate result, between that of the cone meter and the Venturi.

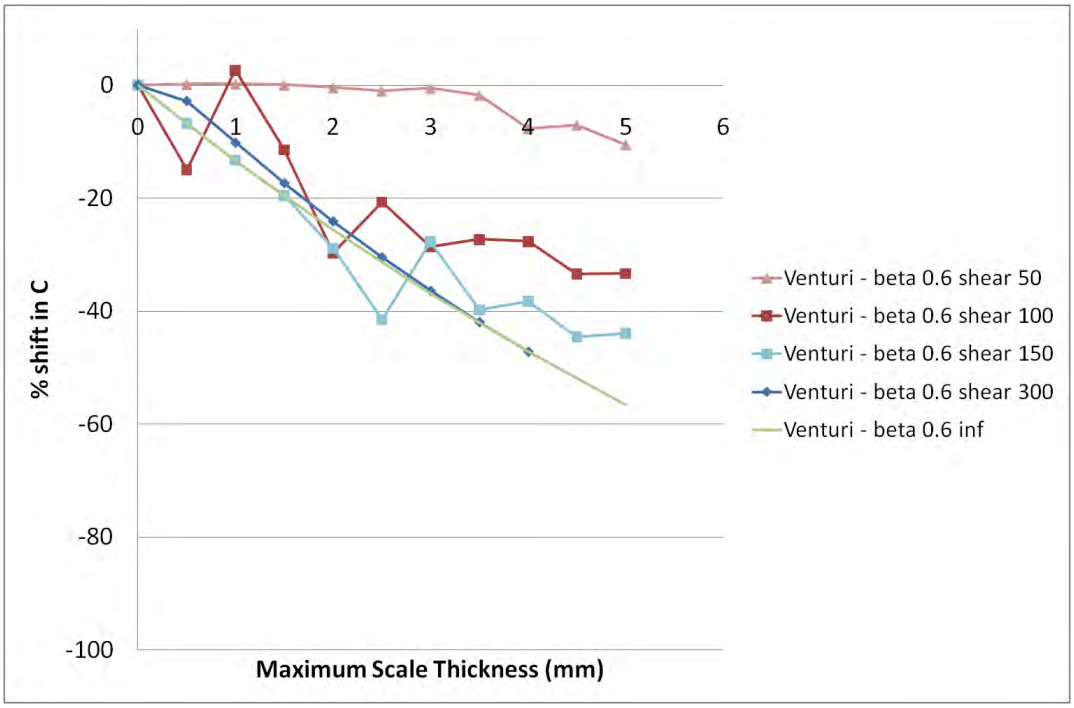


Figure 73. Response of a beta = 0.6 Venturi to scour-sensitive scale with thresholds between 50 and 300 Pa (inf = uniform build-up)

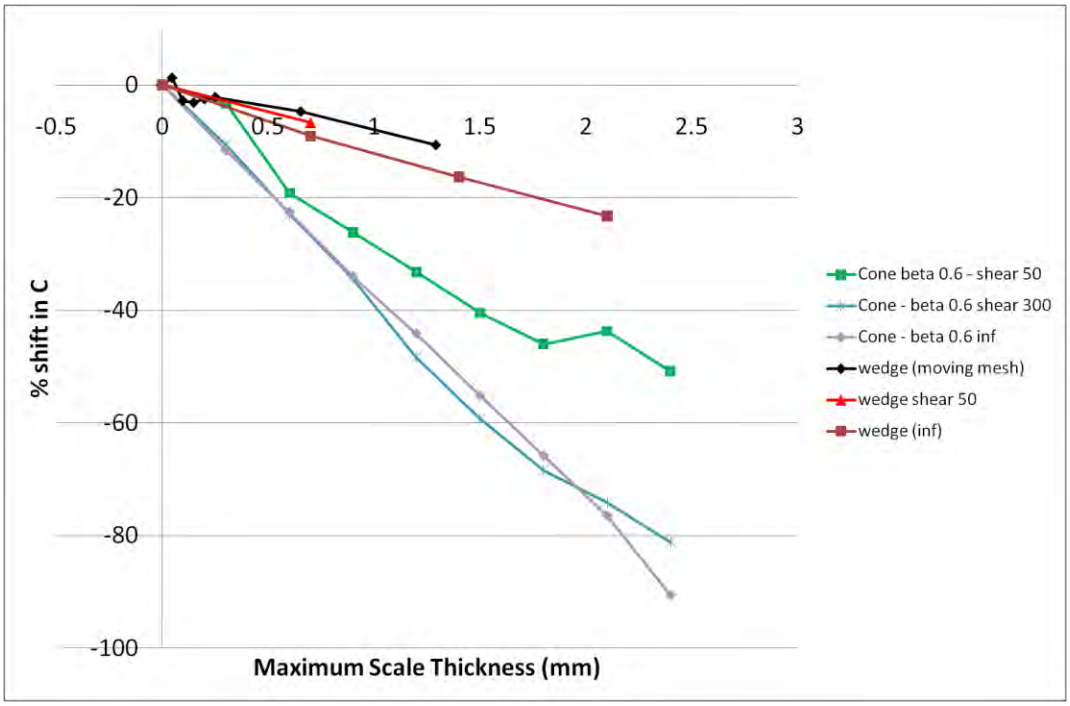


Figure 74. Response of a beta = 0.6 equivalent cone and a beta = 0.707 wedge to scour-sensitive scale

6.12 CFD – Simulated Pressure-Sensitive Scale Growth

Calcium carbide scale, in particular, is known to build up in locations with a low local pressure. To simulate this behavior, CFD models were constructed and analysis was performed similar to the shear-sensitive CFD simulations. However, in this case, scale was deposited when the local pressure (relative to the pressure at the meter outlet) was below a threshold value.

Figure 75 is a velocity contour plot for a cone meter. But the geometrical model used to represent the cone meter illustrates typical scale growth that the pressure-sensitive scaling model produces for a cone meter. For this meter low pressure zones occur at the walls in the location of the "vena contracta" and on the back face of the cone at its widest point. In general, the pressure-sensitive scaling model tends to produce quite pointy protrusions at corners. In reality, depending on the mechanical strength of the scale, fluid shear forces would round off these corners. This would affect the pressure distribution and hence affect the overall distribution of scale. Therefore, the pressure-sensitive scaling model may be less realistic than the shear-sensitive scaling model.

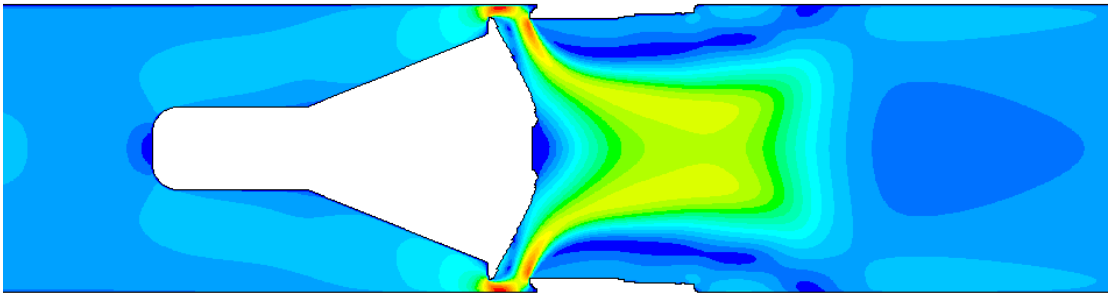


Figure 75. Velocity contours in a cone meter with pressure-sensitive scale

Figure 76 shows the predicted meter response to pressure-sensitive scale for Venturi, cone and wedge meters. It should be noted that a threshold of -1000 Pa represents a more aggressive scaling that -4500 Pa.

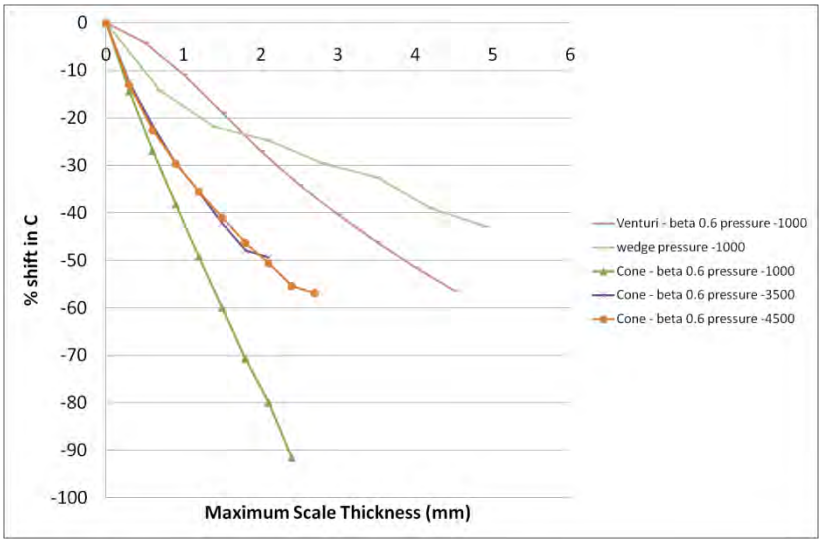


Figure 76. Response of a beta=0.6 Venturi, an equivalent cone meter and a beta=0.707 wedge meter to pressure-sensitive scale

Again, all three meter types exhibit a negative shift in discharge coefficient due to pressure-sensitive scale. The overall effect is similar in magnitude to that of the shear-sensitive model. The response of the Venturi and wedge meter is similar. The cone meter is more sensitive to scale growth when scale forms near the gap between the cone and the wall.

6.13 CFD – Simulated Scale Build-up by Particle Accretion

Some types of scale form when particulates precipitate out of the carrying fluid and stick to walls forming accretions. A CFD model was developed to model this behavior in water flow through 2-inch meters.

The simulation process has much in common with the sand particle simulation method used in the RPSEA erosion studies. First, the flow of water through the meter is calculated, as in a standard CFD simulation. Then numerous 50 micron particles (with a density similar to that of sand particles) are injected at the meter inlet and carried through the meter by the fluid flow. When a particle hits a wall, it sticks. The number of particle impacts on each wall cell surface are recorded and used to calculate an accretion rate in terms of kilograms of particles that impact per square meter of surface area. If the local accretion rate exceeds a threshold value then scale builds up.

Figure 77 shows typical results produced by the accretion model. As the particles were small and carried within a relatively dense liquid the particles tended to follow the liquid streamlines even when the flow changed direction. As a result, the particles usually did not impact with the meter's walls. An exception was in regions of high turbulence, close to the cone meter walls and immediately downstream of the cone itself. In these regions particles travelling close to the walls were buffeted by randomly occurring turbulent eddies and the particles did impact onto the walls. The result of this phenomenon is that scale builds up in a random, rough pattern in regions of high turbulence.

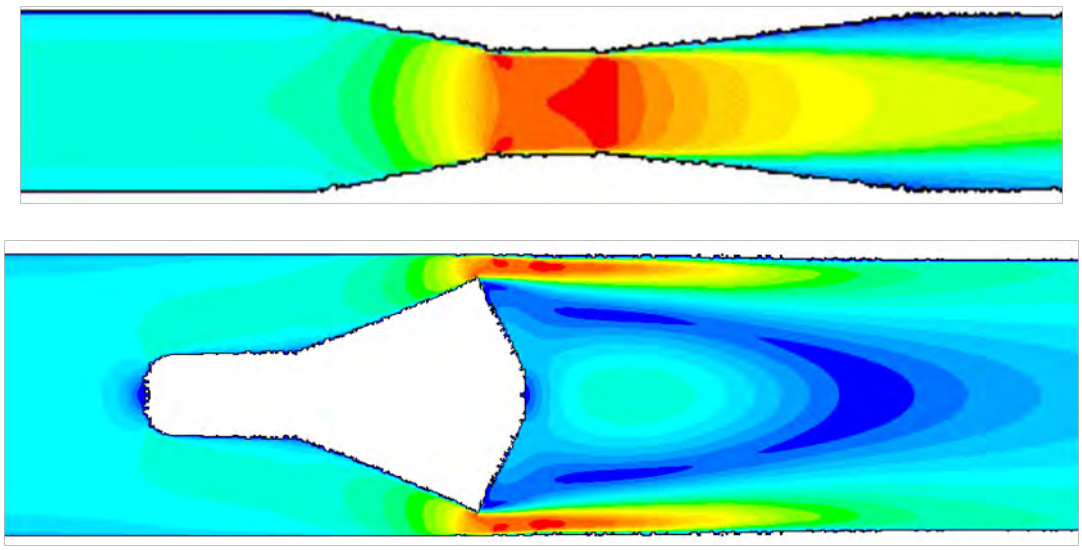


Figure 77. Velocity contours in a Venturi meter and a cone meter with accreted scale

Figure 78 shows that the accretion process causes an erratic negative shift in discharge coefficient for both cone meters and Venturi meters. The magnitude of shift is similar to that in the previous CFD models and in the experimental test results.

The semi-random way in which the scale builds is the primary cause of variability in this case. As in previous examples, the Venturi meter fairs better than the cone meter in like-for-like

conditions. Attempts to model the wedge meter using the accreted scale model were unsuccessful.

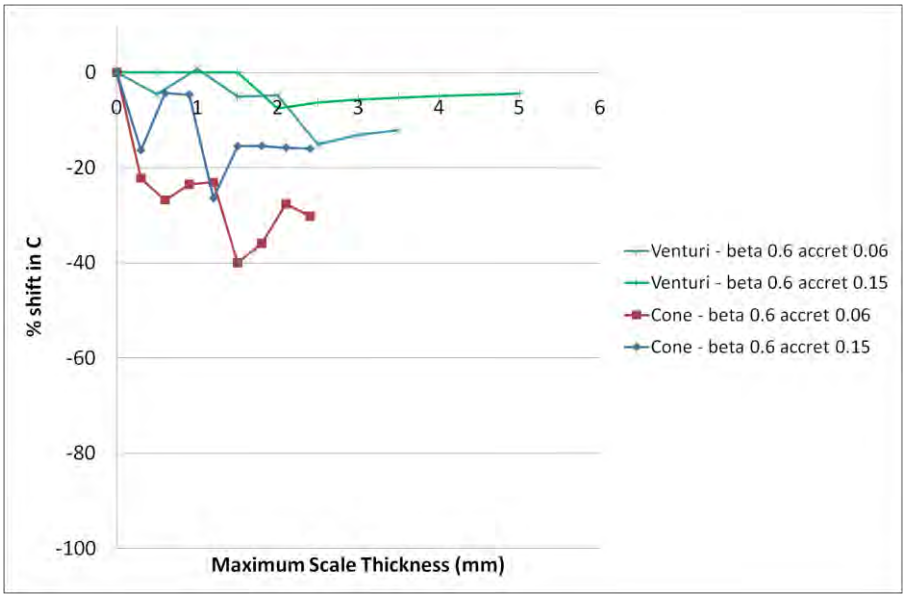


Figure 78. Response of a beta = 0.6 Venturi meter and an equivalent cone meter to accreted scale with accretion thresholds of 0.06 and 0.15 kg/m2

Particle trajectories depend very strongly on the flow velocity, the density of the carrying fluid and the particle size. In high-velocity, high GVF (two-phase flows) or single phase gas flows, particles are more likely to build up on upstream-facing surfaces and this produces a different meter response.

6.14 CFD – Simulated Temperature-Sensitive Scale Growth

Scale formation is often associated with hot or cold surfaces. It was thought possible that one meter type might have an advantage over another meter type, in a subsea environment, if the temperature distribution on its wetted walls was favorable for scale formation. To investigate this scenario, a series of CFD simulations were run to predict the temperature distribution in flow meters operating under typical subsea conditions.

The first set of simulations modeled water flow at a flow velocity of 3.4 m/s through 2-inch Venturi, cone and wedge meters. The meter walls were 1 inch thick and made of steel. The water density, specific heat capacity and thermal conductivity were set to 1000 kg/m^3, 4182 J/kg K and 0.6 W/m K respectively. The external sea temperature was set to 4°C with a heat loss

coefficient of 800 W/m²K. This latter value represents a relatively high, but realistic heat loss typically seen in subsea pipe work. The inlet water temperature was set to 50°C.

Figure 79 shows the predicted temperature distribution in the flow meters modeled. Note that the figure shows the temperature distribution through the flow meter walls as well as the temperature distribution in the flowing fluid. It was found, for the assumed fluid flow and thermal conditions, that the thermal capacity of the fluid flow was high enough so that the temperature of the wetted walls (the inside surface of the meter, not the outside surface) was effectively that of the flowing fluid. This suggests that in most liquid flow scenarios, a temperature sensitive scale would grow at a similar rate on all of the meters.

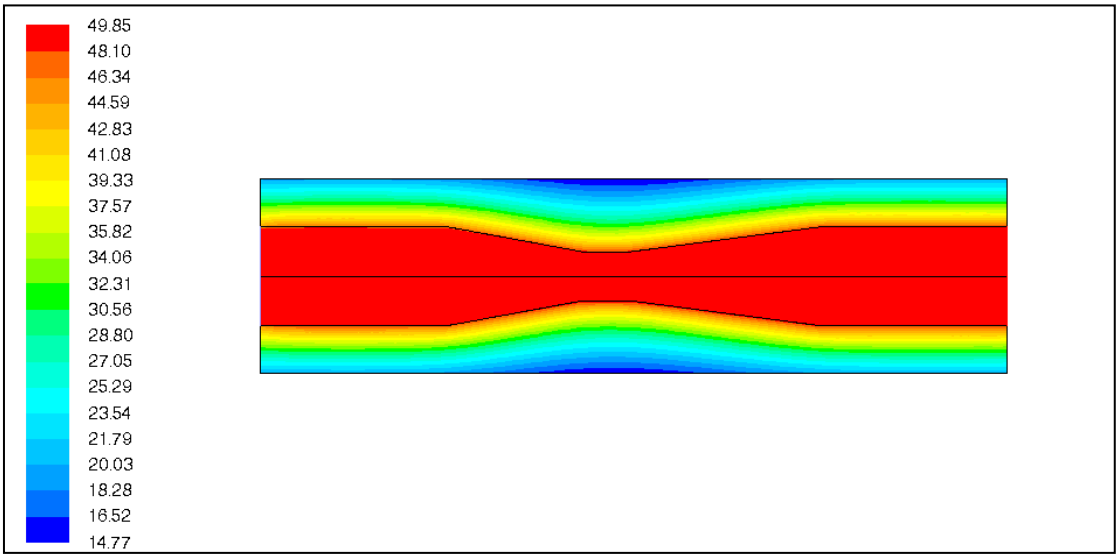


Figure 79a. Temperature contours (oC) for a Venturi meter in water flow

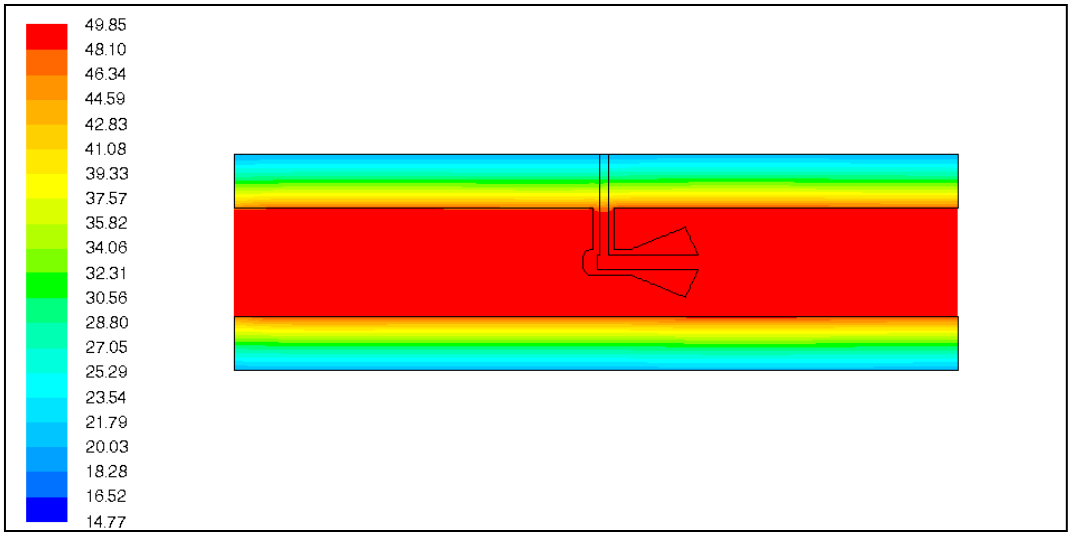


Figure 79b. Temperature contours (°C) for a cone meter in water flow

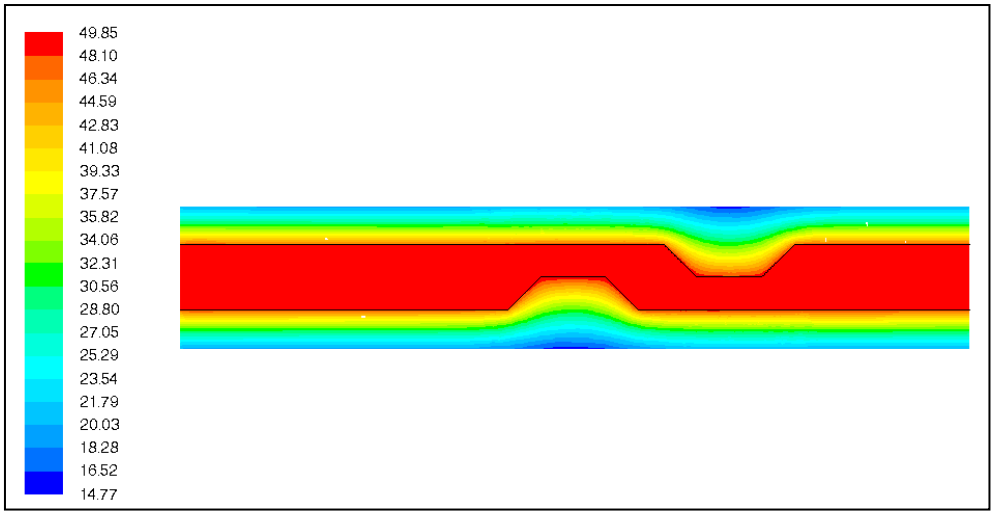


Figure 79c. Temperature contours (°C) for a wedge meter in water flow

Additional CFD runs were then performed to investigate the opposite extreme in which the meters measure gas flow. In these models, the gas was selected to be methane at 20 bar with density, specific heat capacity and thermal conductivity equal to 31.7 kg/m^3, 2570 J/kg K and 0.0425 W/m K respectively. The inlet gas flow temperature, sea temperature and other parameters were specified the same as in the previous simulations.

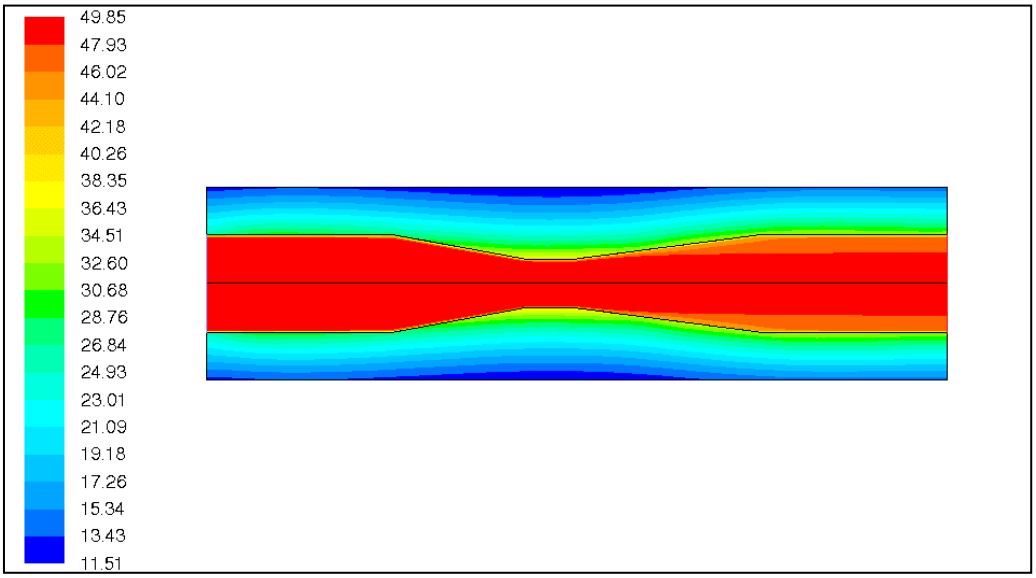


Figure 80a. Temperature contours (oC) for a Venturi meter in gas flow

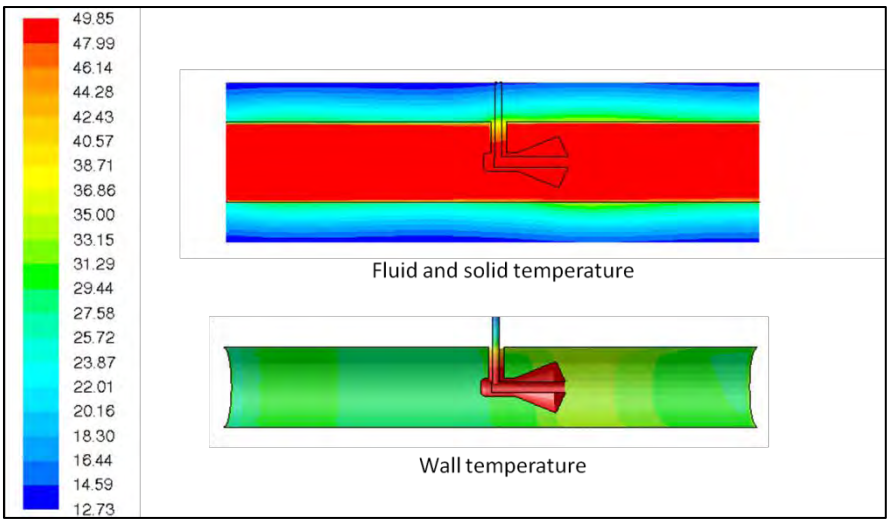


Figure 80b. Temperature contours (°C) for a cone meters in gas flow

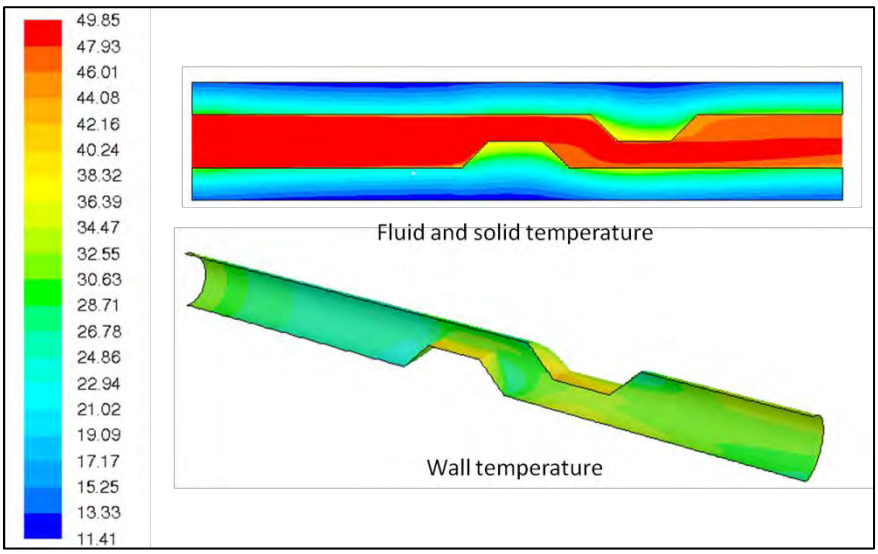


Figure 80c. Temperature contours (°C) for a wedge meters in gas flow

Figure 80 shows that some variations in the meter inner surface temperature are apparent. In the Venturi and wedge meters, the throat surfaces are roughly 10°C hotter than the pipe walls. In the cone meter, the pipe walls are about 20°C cooler than the cone surface. This could lead to scenarios for temperature dependent scaling in which scale forms on some surfaces but not on others.

Figure 81 shows the results of a theoretical analysis, assuming that the primary effect of scale is to change the effective beta value of the meter. It can be seen that if uniform scaling occurs only on the walls of the cone meter or only on its cone, then the shift in discharge coefficient is

smaller than for a cone meter with uniform scale on all surfaces. However, non-uniform scaling that does not invade the throat region causes large positive shifts that could compensate for the negative effects shown in Figure 81. Scenarios in which scale forms only on the cone could result in either positive or negative flow coefficient shifts.

Figure 81 also shows that if scale material is added to the Venturi pipe walls (assuming no tapping blockage), then the effective beta value increases, reducing the pressure difference across the meter and thus causing a positive shift in discharge coefficient.

The wedge meter is expected to behave in a similar manner to the Venturi meter.

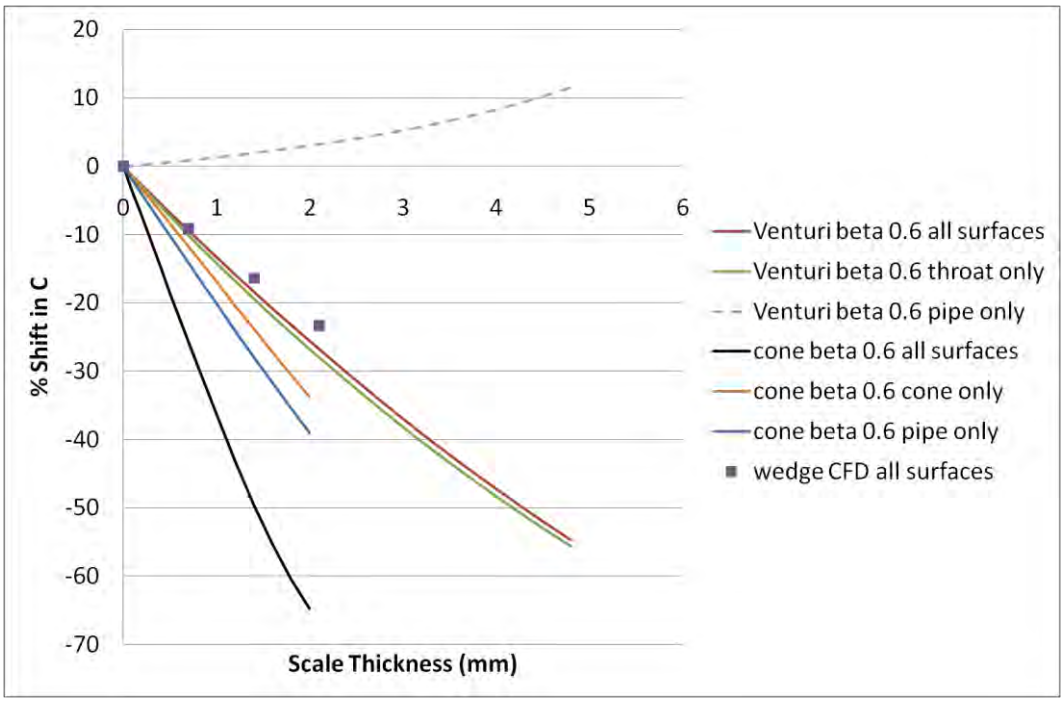


Figure 81. Theoretically calculated effect of smooth uniform scale on specific surfaces

It should be noted that thermally-controlled scale formation may well be strongly influenced by the length and frequency of shut-down periods. During times when there is no fluid flow through the meter, the temperature of the wetted walls of all flow meters will approach that of the surrounding sea water temperature. As seen in the Intertek tests, temperature cycling can induce scaling.

6.15 CFD – Simulated Scaling Around Taps

All of the previous analyses have assumed that the pressure taps are fully open and unaffected by scale formation. However, the test results clearly showed that pressure taps are prone to blocking with scale. Obviously total blockage of a pressure tap will invalidate any flow

measurement. Simulations were run to look at the effect of partial blockage of 3 mm and 6 mm taps in water and gas flow through a 2-inch pipe. The results from two simulations of the 3 mm tapping are shown.

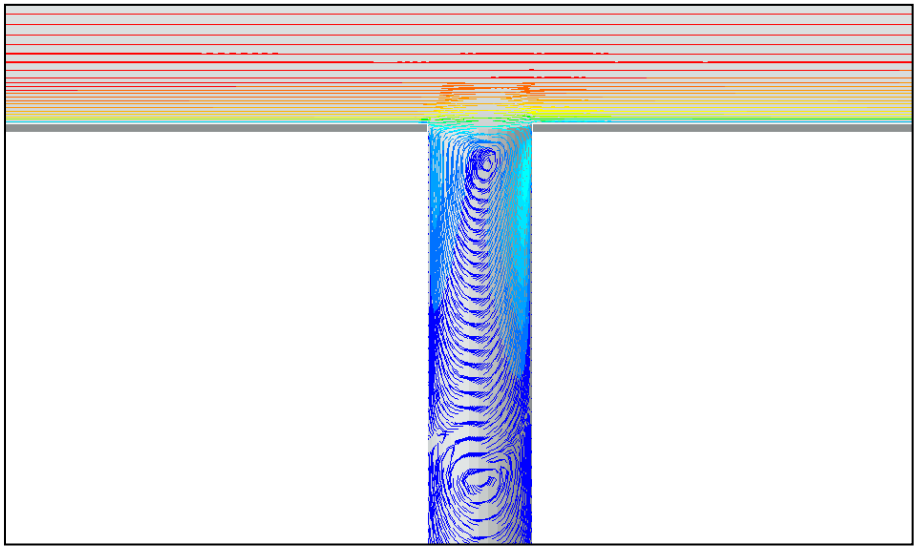


Figure 82a. No scaling in the pressure tap

Initially a pristine, sharp-edged pressure tap was modeled. The pressure at the base of the pressure tap is about 166 Pa higher than that in the free stream of the flowing fluid.

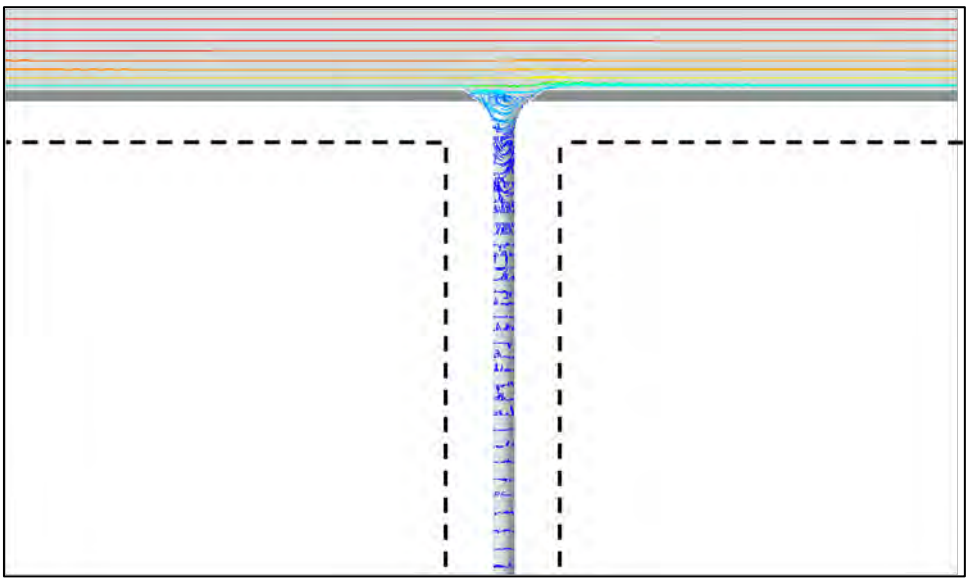


Figure 82b. 1.2mm of scale in the pressure tap and on the inside surface of the meter.

Uniform layers of scale material were added to the wall surface and on the inside surfaces of the tapping in progressive simulations. This narrowed the tap, rounded its edges, and effectively deepened the tap slightly as scale was added to the pipe wall as well.

Figure 83 shows how scale thickness affects the measured pressure. Adding scale does not change the static pressure measurement error by much until the scale reaches a thickness of 0.9 mm. For scale thicknesses greater than 0.9 mm, the static pressure indicated by the scaled pressure tap increases. This pattern appears to be consistent for 3 mm and 6 mm holes and in gas and water flow.

Figure 83 shows that for a clean tap, the pressure at the base of the tap is about 166 Pa higher than that in the free stream. This is the normal "static hole error" as described by Gibson[12]. Discounting normal static hole error, 1.2 mm of scale has been calculated to cause an additional -0.3% measurement error in a 2-inch beta = 0.5 Venturi meter with 3 mm taps for a pipe Reynolds number of 153,000.

Effectively this analysis shows that, provided the pressure tap remains open, scale formation within the tap will have a small effect compared with equivalent scale formation in the throat of a meter. Larger taps are advantageous because they would require a greater amount of scale deposition before the tap becomes fully blocked.

[12] Gibson, J.G. The static hole error problem in Venturi meters operating in high-pressure gas flow. PhD Thesis, Strathclyde University, 2001.

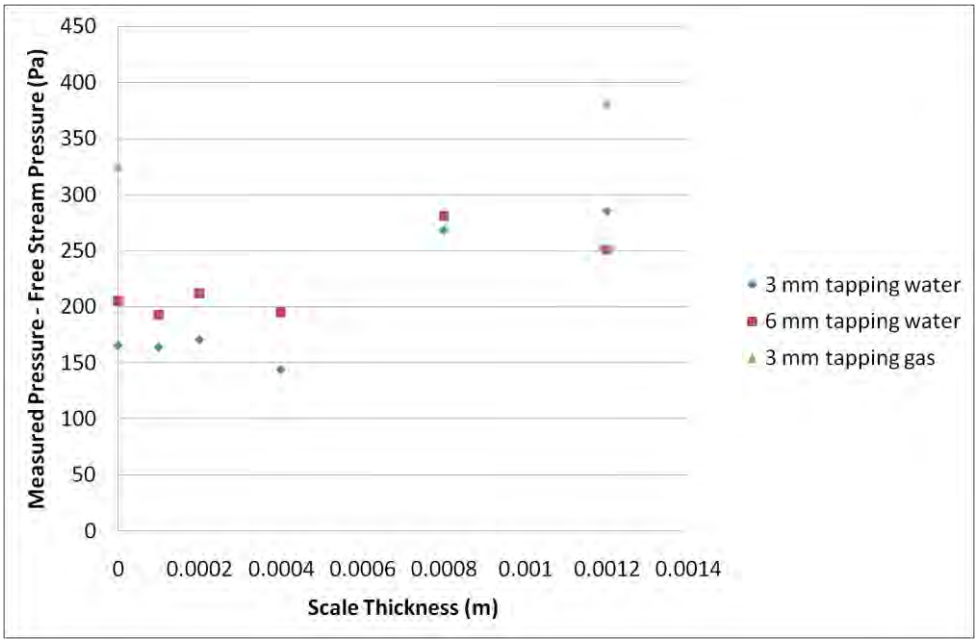


Figure 83. Difference between the measured and free-stream pressures for different scale thicknesses

Note that the scale was assumed to be smooth in this case. Wall roughness would also be expected to alter flow behavior in the boundary layer, which would in turn affect the flow pattern in the tap and the resultant static pressure measurement error. The effect of wall roughness is probably of a similar order to that shown in these CFD simulations.

6.16 Summary of All Scaling Work

Computational Fluid Dynamics (CFD) methods have been used to study the effects of scale formation in subsea differential pressure flow meters. Based upon (1) the results of the simulations run, (2) the experimental data from tests carried out by Intertek, and (3) previously published information; the following conclusions have been drawn.

- Scale formation is complex and "case dependent". The experimental tests showed that subtle factors, such as surface finish can have a significant effect. This makes modeling of specific cases impractical. However, CFD can be used to compare the responses of different meters to the same scale formation mechanisms.
- The CFD models run in this study do not fully model the complex process of scale formation in subsea environments. However, the modeling methods used are sufficiently realistic to provide an insight into the effects of scale on flow measurement accuracy.
- The CFD-based study by TUV NEL implies that Venturi meters are better than cone meters from a scaling point of view. However, the cone meter performed better in the experimental tests at Intertek. It is possible that scale growth on the cone meter was less than that on the

Venturi meter in the Intertek tests because of the fabrication quality and the surface finish (for example, the corrosion on the Venturi meter flanges). Although useful and illustrative, the experimental tests were not a perfect like-for-like comparison.

- Given the variability of the test results the information available does not clearly and consistently show that one meter type is superior to another meter type in terms of sensitivity to scale formation.
- The CFD predictions showed that scale can produce both positive and negative shifts in discharge coefficient under artificially-defined conditions. However, the more realistic models consistently produced negative shifts in discharge coefficients, as was also seen in the experimental tests. It seems likely that most subsea scaling events would result in a negative shift in discharge coefficient (i.e. an over-measurement of the fluid flow rate) but that occasionally positive shifts (under measurement) could occur.
- Surface roughness causes a negative shift in discharge coefficient and is particularly important in meters in which there is a large separation between the pressure taps. The wedge meter was found to be most sensitive to wall roughness as it has a high beta ratio and the relatively large wetted wall surface area between the taps. Wall friction losses would become a more significant fraction of the total differential pressure. Thick films of scale and rough patches of less than 0.02 pipe diameters in height will produce errors of the order of 1%. Thicker accretions, that do not block tapings, will probably cause errors of the order of 20% or more.
- Scale on the cone of a cone meter can cause both positive and negative shifts in discharge coefficient. Scale on the upstream face causes a relatively small positive shift. Scale on the downstream face could cause very large positive shift. If the scale extends into the throat then this will cause a large negative shift.
- Scale on the walls of a cone meter has little effect if it is upstream of the cone (except when it is close to the throat). If it is more than one pipe diameter downstream it will probably have little effect on the flow measurement. If the scale on the pipe wall is nearer than one pipe diameter, then it will interfere with the vena contracta and very large positive or negative errors could result.
- Scale on the convergent and divergent sections of a Venturi has relatively little effect unless the scale extends into the throat. Dependent upon the location of the scale deposits in the throat of a Venturi the measurement error can be either positive or negative. The magnitude and sign of the error in this scenario will be highly dependent on the shape and distribution of the scale formed in the throat.
- Large beta meters and large diameter meters are preferable to small beta meters as a given thickness of scale will cause a smaller change in the effective beta value.

- As a rough estimation method, scale effects will be similar to an equivalent change in beta (assuming that the pressure tap remain open). Provided they are fully open, then the errors caused by scale in and around the tapings are likely to be relatively small.
- Large pressure taps are preferable to small pressure taps in that more scale can form within them before they are fully blocked. However, it should be borne in mind that large impulse lines may act as large reservoirs of static, cold fluid that could promote scale formation, thus accelerating blockage.
- Rough surfaces, corrosion, surface blemishes and scratches are associated with scale formation and these factors appear to have affected the results of the scaling tests. Ideally, flow meters should be fabricated with mirror-finish surfaces and entirely of corrosion-resistant material if scaling is perceived as an issue.
- In a subsea context, once scaling starts, (and assuming that scaling can be detected), then the best practical approach would be to assume that the meter is over-reading. If the meter can be removed and inspected then the information given in this report may give an indication of magnitude and sign of the errors incurred. Depending on the nature of the scale it may be feasible to measure its extent before and after cleaning (probably by means of three-dimensional laser scanning) and to produce a CFD model of the meter before and after scaling. Recalibration of the meter may also be an option worth considering.

7. Deliverables

The original project deliverable were:

1. Experimental and CFD results for three commonly used multiphase meter elements (Venturi, cone and wedge meters) altered by synthetic deposition and erosion. The meter's response before and after alteration is captured for different meter designs and degrees of alteration. **Achieved**
2. An interpretation of the results is made to give a clearer understanding of these effects on meter response. **Achieved**
3. Models are created to predict the effects of meter fouling on meter performance. **Achieved well for erosion, but not as well for scale deposition**
4. Both the experimental results and the interpretations are recorded in the task final report, together with recommendations for further work. **Achieved**
5. Papers and presentations at industry conferences will be used to disseminate the results in a public forum. **A paper was presented to ThAW, in May, 2010 on erosion testing and CFD analysis of erosion effects as part of technology transfer. Another ThAW paper on**

erosion was presented in April, 2011 and a paper has been accepted for NSFMW in October, 2011.

8. Conclusions

A large number of CFD simulations have been run to investigate sand erosion effects in Venturi, cone and wedge meters operating under conditions likely to be experienced in subsea metering installations. Equations have been developed which predict the pipe wall penetration rates and the effect of erosion on meter accuracy.

- The equations developed in this project are intended to provide an order of magnitude method for estimating erosion effects in subsea flowmeters and hence to indicate whether further testing or modeling of a specific installation is desirable.
- Particle erosion is a sensitive and potentially unstable process. Even the best-optimized erosion prediction methods do not predict erosion rates to a high level of accuracy. Due care must be taken and engineering judgment applied when using these methods.
- Overall there was a reasonably good agreement between the CFD simulations and the limited test data.
- Erosion effects are highly dependent on the operational parameters such as the flow rate, the liquid fraction, the sand rate and, to a lesser extent, the sand particle size.
- Small beta ratio flowmeters suffer more from erosion than larger beta meters.
- Flowmeters are often placed close to downstream elbows, bends or similar fixtures in subsea installations. All differential pressure meters tend to accelerate erosion in downstream bends.
- Erosion in the Venturi was not as easily characterized as cone and wedge meters, because the CFD struggled to correctly predict erosion in the throat and taps. However, it should be noted that Venturi meters were affected by erosion much less than the cone and wedge meters.
- On balance the Venturi meter would appear to be the most erosion-resistant design. However, Venturi meters are often more damaging to downstream bends and this may be a severe limitation in some applications.
- As their throat is formed by a narrow annular gap between the cone and the pipe wall, a cone meter will be more affected by erosion than an equivalent Venturi. However, cone meters are usually less damaging to downstream bends than equivalent Venturi meters.
- Wedge meters are prone to wall penetration failure adjacent to the upstream edge of the downstream wedge. The metering error of a wedge meter will be intermediate between a

Venturi and cone meter of equivalent beta ratio. They will accelerate erosion in downstream bends, but this effect will be smaller than for a Venturi.

A large number of CFD simulations have been run to investigate scale deposition effects in Venturi, cone and wedge meters to assess how they are affected by scales which are sensitive to fluid scouring, pressure distribution, particle accretion and thermal effects. It was not possible to develop equations which predict the effect of scale on meter accuracy. However the following observations can be made:

- Scale formation is a complex process and will vary significantly from case to case.
- Scale can result in large positive or negative errors. On balance, the information available suggests that over-reading is more likely in most cases.
- Scale formation is highly dependent on the surface condition. The use of meters with smooth, polished surfaces or surfaces coated with a smooth material may reduce scale effects.
- There is therefore no clear and consistent advantage of Venturi, wedge or cone meters over each other.
- Larger beta ratio meters are generally less prone to the effects of scaling than small beta ratio meters.
- Larger meters are generally less prone to the effects of scaling than small meters.
- Large taps are less prone to blockage. However, the extra static fluid in large taping impulse lines may promote faster scale formation. There is therefore no clear recommendation for tap size.

8.1 Areas for Continued R&D Investigation

There are several areas that could merit continued investigation including finding direct methods that could indicate the presence of a fouling and erosion condition. Some possible approaches include:

- Examining the possibility of diagnostics including tomography
- Using a water salinity detector to detect scale.
- Using additional differential pressure measurements.
- Using actual meters, virtual meters and mass balance techniques.

The present project on meter fouling and erosion has been fairly limited and could be extended to:

- Multiphase composition measurement elements

- Consider upstream fittings and mixing (blind Tee)
- Consider whether the meter affects other downstream fittings
- Determine where fouling and erosion occurs in complete multiphase meters
- Find the effect on meter performance
- Evaluate meter sensitivity to alterations

Another approach could be to avoid fouling and erosion or at least try to minimize it. This might be achieved by meter design, installation and sub-sea processing. Removing water would cure scale deposition. Removing sand would cure erosion. Sub-sea processing is very expensive, but is being considered for other reasons.

A guide to selecting the best metering system to reduce the errors caused by fouling and erosion at the design stage could be produced.

Finally, there is some hope that the CFD simulation methods could be improved to better characterize erosion in Venturi meters.

Appendix A- Budget and Finances.

Task 5 - Meter Fouling Effects	Actual Cost
Direct & Contract Labor Costs Thru June 2011**	$160,359
Labor G&A	$10,910
Estimated Other Direct Costs	
Travel & Expenses Thru June 2011***	$1,755
Travel & Expense G&A	$167
Estimated Special Testing	
Subcontracted Effort Thru June 2011***	$252,995
Subcont G&A	$20,821
Cost Share Amount (%)	20%
Cost Share Amount ($)	$89,401
Net RPSEA Cost ($)	$357,606
Total Estimated Cost Thru June 2011	$447,007
Original Total Estimated Cost	$550,904
Cost Through June 2011 with O/H and G&A****	$448,456
** Labor Costs of Direct and Contract with O/H	
*** Subcontracted Costs are without G&A	
*** Travel and Expenses are without G&A	
**** Refer to RPSEA Cost Summary Schedule as of June 2011	

We have saved about $100,000 from the original budget due to:

1. Conocophilipps provided Venturi erosion test results, allowing CFD to be considered.
2. The use of CFD saved the cost of purchasing more flow meters to test.
3. The CFD simulations reduced the cost compared to physical testing.
4. The CFD was used for both erosion and scale deposition.
5. The JIP considered wax deposition not an HP/HT problem, reducing the work.

RPSEA

Metering System Uncertainty

07121-1301-Task 6.FINAL

Improvements to Deepwater Subsea Measurement

07121-1301

October 8, 2011

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Abstract

Flow rate measurement uncertainty analysis is a key methodology for addressing production allocation, reservoir performance optimization, operational issues, and regulatory requirements. Unfortunately, no unique collection of procedures is currently available for predicting the total system uncertainty associated with multiphase flow meters (both subsea and topside), well test separator systems, and the pipelines connecting them, especially for commingled flow configurations. This lack of tools for understanding and predicting uncertainty causes significant problems for all parties involved, especially for fiscal allocation of production, with reservoir management, and with proper forecasts for operation of process facilities.

In this task, a software tool with a user-friendly interface for predicting total network uncertainties for systems with subsea multiphase flow meters (MPFMs) was developed. The tool accounts for meter operating conditions, in-situ PVT properties, system configurations and flowline/riser effects. It is anticipated that this tool is attractive to all industry stakeholders, such as vendors, oil industry operating companies, and regulatory agencies, in order to more equitably allocate production and optimize reservoir performance.

This report reviews the project objectives and presents results. The capabilities of the software tool, along with screenshots are also presented. Links to more detailed explanations are provided for Joint Industry Project members.

Prepared by:	Approved by:
Eric Kelner, P.E. (LHG)	
	Date: **October 8, 2011**

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1. Introduction

Flow rate measurement uncertainty analysis is a key methodology for addressing production allocation, reservoir performance optimization, operational issues, and regulatory requirements. Unfortunately, no unique collection of procedures is currently available for predicting the total system uncertainty associated with multiphase flow meters (both subsea and topside), well test separator systems, and the pipelines connecting them, especially for commingled flow configurations. This lack of tools for understanding and predicting uncertainty causes significant problems for all parties involved, especially for fiscal allocation of production, with reservoir management, and with proper forecasts for operation of process facilities.

In this task, a software tool with a user-friendly interface for predicting total network uncertainties for systems with subsea multiphase flow meters (MPFMs) was developed. The tool accounts for meter operating conditions, in-situ PVT properties, system configurations and flowline/riser effects. It is anticipated that this tool is attractive to all industry stakeholders, such as vendors, oil industry operating companies, and regulatory agencies, in order to more equitably allocate production and optimize reservoir performance.

1.1 Motivation

Accurate flow rate measurement has become a critical issue for the oil industry, especially for offshore and subsea developments. Multiphase flow measurements are traditionally made using a well test separator and a single-phase metering system topside. In recent years, multiphase flow meter measurements topside and subsea have been accepted for well tests, when the meters are operated within meter specifications and near calibrated conditions. However, no reliable uncertainty models that couple multiphase flow in flow lines with the separator and meter uncertainty under flowing conditions existed until now.

The unacceptable consequences of undetected or unassessed uncertainty in subsea measurement systems are well known.[1] Recognizing the issue and attempting to account for uncertainty effects, special methods of allocation have been proposed.[2,3] A large part of the API Recommended Practice 86, Measurement of Multiphase Flow,[4] was dedicated to the topic of uncertainty. The DeepStar consortium dedicated a significant part of its Project

8302[5] to addressing the topic, with a comprehensive listing of sources of uncertainty in subsea measurement, as well as several examples showing how the uncertainties in conditions (e.g., fluid properties) can adversely affect meter results.

Use of a test separator is a common technique for MPFM performance verification. However, in order to be effective, it is important to assure that the separator performance is acceptable and meets its specifications. Also, reliable mechanistic models are needed for predicting the separator uncertainty. Thus, it is necessary to understand the performance of the vessel as well as the meters for predicting the metering system uncertainty.

A protocol for the prediction of well test measurement uncertainty using a mechanistic model of separator vessel performance incorporating inlet gas and liquid entrainment, and inlet bubble and droplet size distributions has been developed[6,7,8] and is shown in Figure 1. Well test measurement uncertainty due to the separator is predicted by combining a:

- Separator inlet flow model,
- Vessel separator performance model, which predicts the amount of gas carry-under in the liquid leg and liquid carry-over in the gas leg,
- Single-phase meter uncertainty analysis.

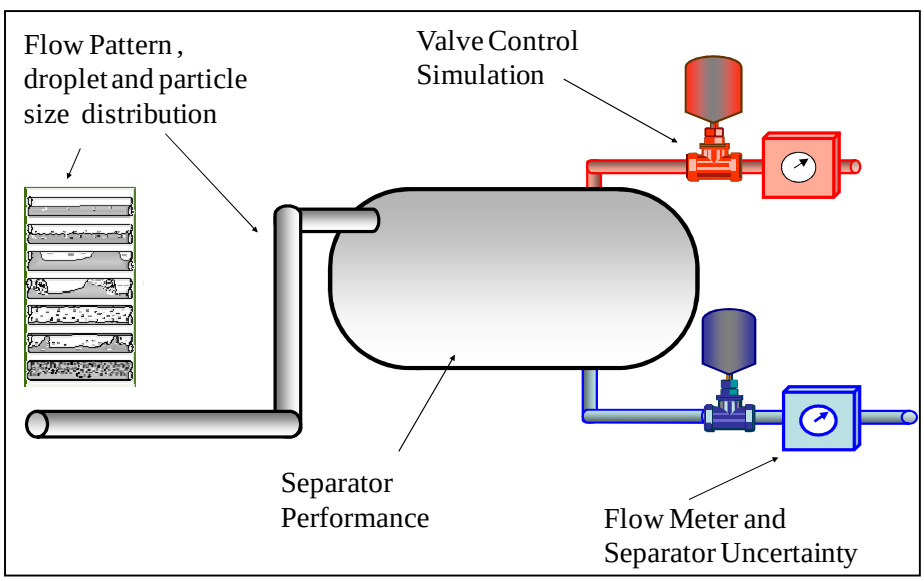

Figure 1. Existing separator vessel well test uncertainty model

An extension of the separator vessel well test uncertainty analysis to include subsea multiphase meters and the flowlines in between, based on the physical principle of the meter and the associated hydrodynamic flow behavior, was carried out to provide a tool to estimate total subsea measurement system uncertainty.

1.2 Benefits to Industry

This project will provide industry stakeholders with a software tool and methodology for predicting uncertainties for systems that incorporate multiphase flow meters, based on the operating conditions, fluid properties, flow conditions and well commingling effects.

Ultimately, knowledge of system-wide uncertainty will facilitate verification of meter performance and fair allocation of produced fluids, provide early indication of measurement problems in the system, and provide all parties, e.g., vendors, operators, partners, service companies, and regulatory agencies, a realistic picture of the measurement quality at all times, incorporating maximum expected variation in the measurement.

2. Organization

An important aspect of the execution of this task was to pull together a team to execute the plan. The team members were:

- Bob Webb, P.E. (BP)-Task Champion. In this role, Mr. Webb served as the lead technical interface between the JIP members, task manager and subcontractors.
- Eric Kelner, P.E. (Letton-Hall Group) - Task Manager. Mr. Kelner was the overall manager of the effort.
- Task Working Group. JIP members who have special interest in the Task technology or application. : BHP Billiton, BP, ConocoPhillips, Chevron, Shell, Statoil, and Total.
- Subcontractor: Multiphase Systems Integration (MSI), who programmed the original separator uncertainty software used in this task and developed the enhancements that became this program's uncertainty tool, known as "UBProdAlloc" (**U**ncertainty-**B**ased **Prod**uction and **Alloc**ation).

3. Details of Task Plan

A Joint Industry Project (JIP) was formed to provide the co-funding required for this task. Each member company also agreed to provide support from those experts in their organizations with specific knowledge in the areas such as multiphase flow measurement, uncertainty and field applications. The approach was to extend the existing separator model to integrate subsea and topside multiphase flow meters, and long flowline/risers, to provide a comprehensive model of total system uncertainty. The development and integration of the additional modules to deliver realistic assessments of system uncertainty would provide many challenges, for example, modeling commingled streams from subsea tiebacks such as loop systems and manifold systems, modeling multiphase meter uncertainty, determination of uncertainty related to PVT calculations, etc.

Two preliminary activities were planned prior to initiating software development. First, a workshop was conducted to determine the specific requirements of the software tool from the user's perspective. Measurement experts from the production and exploration community were asked to provide their insights and operating experience. Second, a desktop study was to be conducted. The desktop study was to incorporate the results of the workshop, and a comprehensive review of prior work on multiphase meter uncertainty, allocation uncertainty, modeling flow in long lines, and separator performance modeling, to account for useful related methodologies. The workshop was conducted as planned. As research progressed on the desktop study, it quickly became apparent that existing technology, such as natural gas transmission uncertainty tools, Excel Monte Carlo simulation add-ins, and other, more erudite academic uncertainty tools were either not sufficient or not easily adapted to the problem at hand. The desktop study effort was abandoned to allow resources to be allocated to software development. Results from the study and additional investigation into uncertainty analysis were incorporated in the "Details and Background" document included as an appendix to this document. Results from the search for existing uncertainty tools and the literature search are also included as appendices to this document.

The analysis tool was to be modular in construction with user-friendly "wizards" implemented where possible. It was decided to use Excel as the main software engine because of its recognizable interface and built-in functions, and because the separator

vessel model was already using Excel. The software simulator was to include two models - one addressing oil dominant systems and one addressing gas dominant systems.

Once completed, the simulator was to be used to examine meter verification and allocation strategies in a Demonstration Phase. The Demonstration Phase was intended to provide potential users with a workshop to familiarize them with the tool. Several measurement system configurations for subsea and topside meters were to be modeled to illustrate the application of the new tools. Suitable guidance documents were to be generated.

3.1 Task 6 Objectives

The objectives of this project were to:

1. Investigate and quantify measurement uncertainty of single-phase meters commonly used on topside separators, as a function of multiphase contamination.
2. Investigate the propagation of uncertainty in PVT models to in-situ flow rate measurement.
3. Conduct flowline/riser flow model characterization
4. Develop an integrated multiphase measurement system performance methodology and user-friendly software tool:
    a. Couple pipeline, separator, and single-phase meters.
    b. Extend the methodology to multiphase meters.
    c. Apply it to both oil and gas dominant systems.
5. Quantify system flow rate measurement uncertainties:
    a. Incorporate effects of steady state and transient conditions, PVT, phase entrainment, separator performance, and meter characteristics.
    b. Applicable to either individual points (e.g., well jumpers) or over the complete subsea-topside span.

3.2 Workshop Held March 9, 2009

3.2.1 Overview

The System Design Workshop was held from 8:00-4:30 at the offices of ConocoPhillips at 600 N. Dairy Ashford Road in Houston, TX. The purpose of the workshop was to further define the uncertainty tool being developed under Task 6 of RPSEA Project 07121-1301. The workshop was intended to clarify the issue being addressed, define possible use cases,

then agree on a user scenario as a developmental target, and develop an initial list of software requirements. Results from the workshop follow.

3.2.2 Workshop Results

Constraints

1. Users will be engineers (initially). Eventually, will be data analysts.
2. Windows XP/Vista/Windows 7.
3. Interface will be Excel/VBA initially.
4. IP release by MSI.
5. How far into guts of meter is considered a trade secret by manufacturer?
6. Separator internals not modeled.
7. Leverage existing MSI tools.

Use Cases

1. **Overall System Balance**
   a) What is normal/abnormal?
   b) Likelihood of "gross" bias.
   c) Use at project level, then at operations level on monthly basis.
2. **Identification of error source**.
   a) Tool to help guide process of elimination
   b) Provide Key Performance Indicators
3. **Design tool.**
   a) Validation.
   b) Move meters to different locations subsea.
   c) Iterative.
4. **Assess uncertainty of separator measurement when used as a reference.**
   a) When validating SMFM.
5. **Validation of reservoir estimated values.**

3.2.3 Selected Operating Scenario

After discussion of several possible user scenarios, the following was agreed as the target Operating Scenario:

> *Use the tool to assess the normal system balance. If balance is outside that normal range during a given month, then use the tool in "reverse" to identify possible mis-measurements. Then use the tool to estimate the uncertainty in a well test to justify/defend well test results. Well test results may indicate the need to service the SMPFM.*

3.2.4 System Requirements

Workshop attendees provided an initial list of system requirements during a brainstorming session.

1. **Internationalization:**
   a) U.S Customary Units, SI units,
   b) English,

2. **Standards**
   a) Comply with Multiphase Systems Integration Software standards.[9]
   b) Comply with American Petroleum Institute/American Society of Mechanical Engineers/American Gas Association standards.
   c) Comply with the Norwegian Multiphase Flow Handbook.

3. **Interface**
   a) When user logs in, he/she should be able to define system.
   b) Able to define base case.
   c) Ability to add to base case.
   d) Ability to add new case.
   e) Ability to save/reload case.
   f) Graphical User Interface definition.
   g) Include a graphical representation of the system.

4. **Input Requirements**
   a) PVT

b) Meter type

c) Meter uncertainty table from manufacturers

d) Pipe diameter

e) Pipe length

f) Pipe elements

g) Lengths

h) Elevations

i) Representative distributions of variables

j) Mass flow rates for each well - water/gas/oil

k) CSV file as outputs from interface becomes input to data link library (dll)

l) Pressure

m) Temperature

n) Also to be determined by application.

5. Flow

a) 3-phase separator

b) 2-phase separator

6. System

a) System to go from wellhead (upstream of choke), through manifold, pipeline, riser, topside, and separator.

b) User can select choke models.

c) User can select choke/no choke.

7. Extensibility

a) Able to add separator modules in series.

b) Able to configure subsea system.

c) Add/remove wells, lines, etc.

8. Speed and Latency

a) Reverse calculations may take hours.

b) Need to estimate reverse runtimes during development.

9. **Fault-Tolerance**
   a) System should be able to restart from some recent previous calculation point.

10. **Support**
   a) Need SW support for 6 months after release for JIP Members. (This was not within the original scope and would require a separate service contract.)

11. **Outputs**
   a) CSV file
   b) Uncertainties of system and subsystems (especially meters)
   c) Echo print of input
   d) Mass units and field units
   e) Flow regime
   f) Indication of oil-dominant vs. gas-dominant - if specific meter is operating near the transition
   g) user-specified, based on user levels
   h) Provide sufficient data to determine/monitor Key Performance Indicators.

4. Execution of the Plan

Code development began after the workshop. JIP members were regularly consulted during development to ensure the software would find applications within the production segment of the oil industry.

4.1 Metering System Uncertainty Tool

The tool, which became known as "UBProdAlloc" (**U**ncertainty-**B**ased **Prod**uction and **Alloc**ation) is a standalone computer program with an Excel user-friendly interface, which is able to predict uncertainties and allocate flow rates for subsea systems accounting for meter operating conditions, in-situ PVT properties, system configurations, subsea-pipeline pressure drop, and temperature changes.

The software can perform the following tasks:

1. Determine the overall system imbalance based on total or phase flow rate measurements or predictions at subsea and topside.

2. Detect abnormal or normal imbalance based on Multiphase Flow Meter (MPFM) and Single Phase Flow Meter (SPFM) measurements.
3. Assess uncertainty of separator measurement when it is utilized as reference.
4. Identify and quantify error (bias) sources.

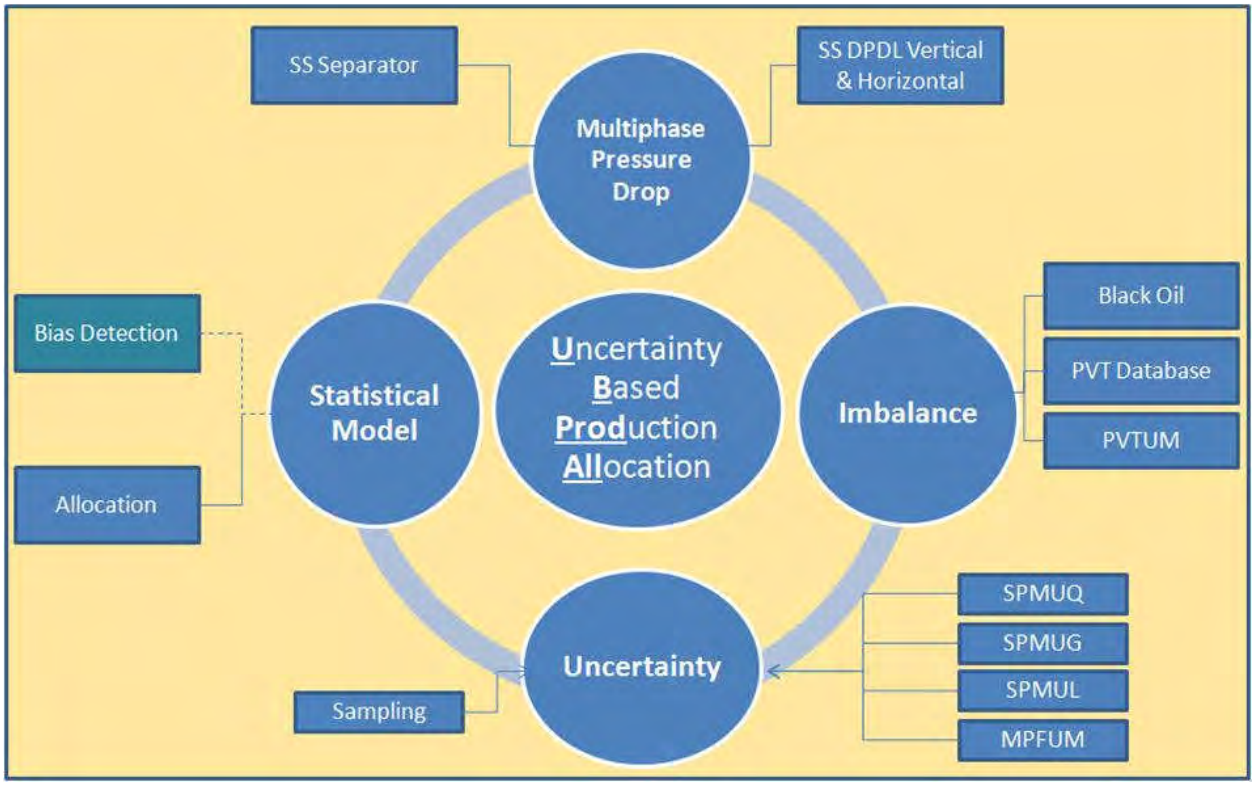

Figure 2. System Architecture Showing Modular Design

The modular design of the software is shown in Figure 2. It is composed of four modules: Multiphase Pressure Drop, Imbalance, Statistical. and Uncertainty Models. These modules interact with each other to determine each phase imbalance, detect the bias presence in overall imbalance, and allocate the flow rate measurements.

The Auxiliary Programs pre-process the uncertainty data required by the UBProdAlloc software. Auxiliary Programs allow the user to enter the uncertainty information related to single-phase and multiphase flow meters and generate Uncertainty Files required by the UBProdAlloc Program.

The Uncertainty Files are text files with different extensions, which identify the type of flow meter (for example .SPG for the single-phase gas meter uncertainty, .SPL for single-phase

liquid meter uncertainty, .SPQ for single-phase quality meter uncertainty - as water cut meters - and, .MPF for the multiphase flow meter uncertainty).

If the user has previously created uncertainty files, they may be used when UBProdAlloc prompts the user to upload uncertainty data. Otherwise, use the Auxiliary Programs to create the Uncertainty Files as input data to the main program. The Auxiliary Programs are listed below.

- SPMUL (Single Phase Liquid Meter Uncertainty Program)
- SPMUQ (Water Quality Uncertainty Program)
- MPFUM (Multiphase Flow Uncertainty Meter Program)
- SPMUG (Single Phase Gas Meter Uncertainty Program)
- PVTUM (Pressure Volume Temperature Uncertainty Tool)

For more detailed information see the software tutorial in Section 5.4.

4.1.1 Simulation Modes

The program offers two modes for simulation: Uncertainty Mode and Metering Allocation Mode. The uncertainty mode attempts to determine the expected values and variances of the oil, gas and water imbalances by propagating the uncertainty of subsea MPFMs or known wellhead flow rates along the production system through the separator. Multiphase flow calculations are carried out in order to determine the flow pattern, phase entrainment, bubble and droplet sizes at the separator inlet. The separator performance is then predicted allowing estimates of the oil, gas, and water flow rates at the separator.

The metering allocation mode estimates the oil, gas, and water imbalances between MPFM and topside meters. If the acceptability criteria for the imbalance are not met, the program proceeds to allocate the imbalance using common methods available to the industry (i.e., Proportional Allocation, API RP-85 and the Unbiased Weight Least Square Method).

UBProdAlloc can handle up to three wells in daisy chain or manifold cluster arrangement. Vertical/two-phase, horizontal/two-phase and horizontal/three-phase topside separators can be simulated by the program. The program is devised for solving the five base cases given in Figure 3 through Figure 7 and discussed below.

4.1.2 Base Cases

The program was designed to run under certain base case configurations, selected by the Joint Industry Project members. The base cases represent the most common configurations utilized in the field. An arrangement is considered a base case when it implies a specific set of computations to determine its uncertainty.

The base cases are:

1. Daisy chain well arrangement connects to a single tieback. MPFM at X-tree or Pipeline End Manifold (PLEM). Three-phase separator at the top side. Gas lift injection into Riser (Optional).
2. Manifold cluster well arrangement. MPFM at X-tree or PLEM. Three-phase separator at the top side. Gas lift injection into Riser (Optional).
3. Daisy chain well arrangement connects to a single tieback. MPFM at X-tree or PLEM. Two-phase separator at the top side. Gas lift injection into Riser (Optional).
4. Manifold cluster well arrangement. MPFM at X-tree or PLEM. Two-phase separator at the top side. Gas lift injection into Riser (Optional).
5. Manifold cluster well arrangement. MPFM installed at Manifold. Two-phase or three-phase separator at topside. Gas lift injection into Riser (Optional).

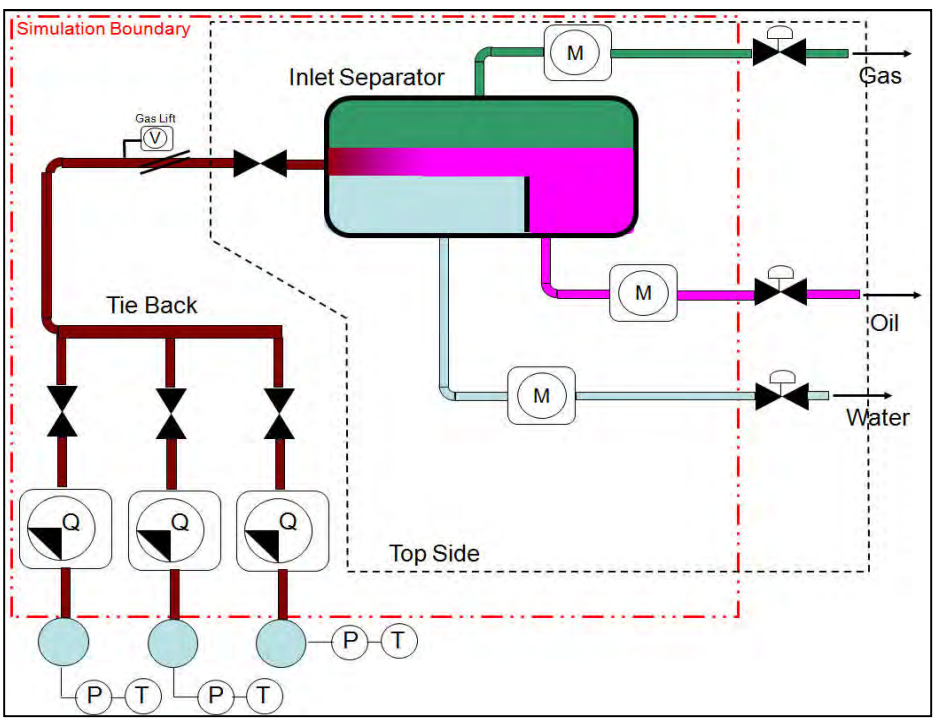

Figure 3. Base Case 1. Daisy chain well arrangement connects to a single tieback. MPFM at X-tree or PLEM. Three-phase separator at the top side. Gas lift injection into Riser (Optional).

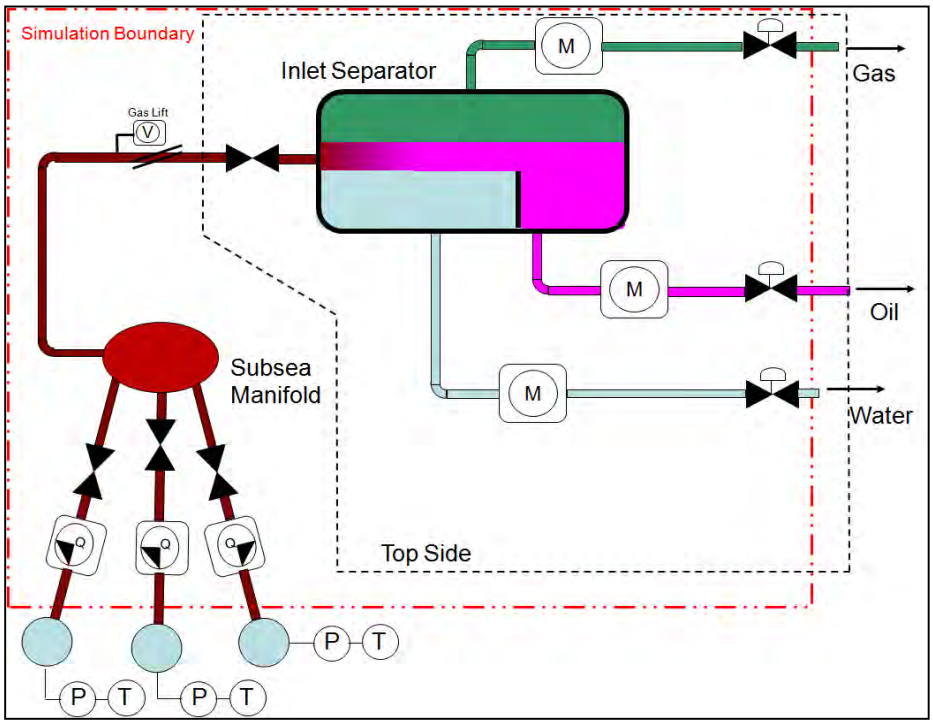

Figure 4. Manifold cluster well arrangement. MPFM at X-tree or PLEM. Three-phase separator at the top side. Gas lift injection into Riser (Optional).

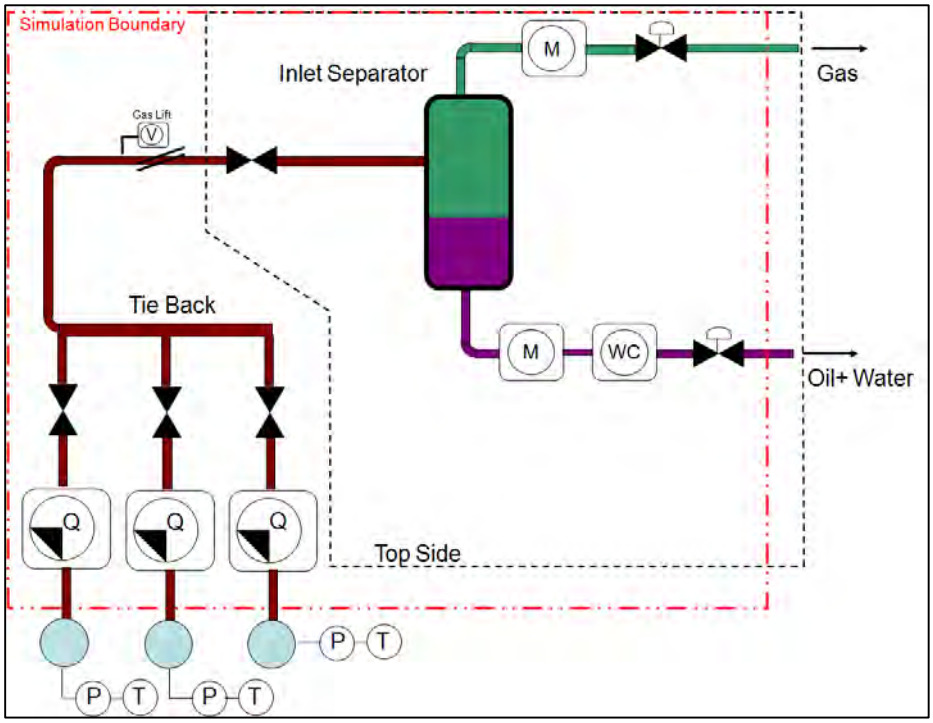

Figure 5. Daisy chain well arrangement connects to a single tieback. MPFM at X-tree or PLEM. Two-phase separator at the top side. Gas lift injection into Riser (Optional).

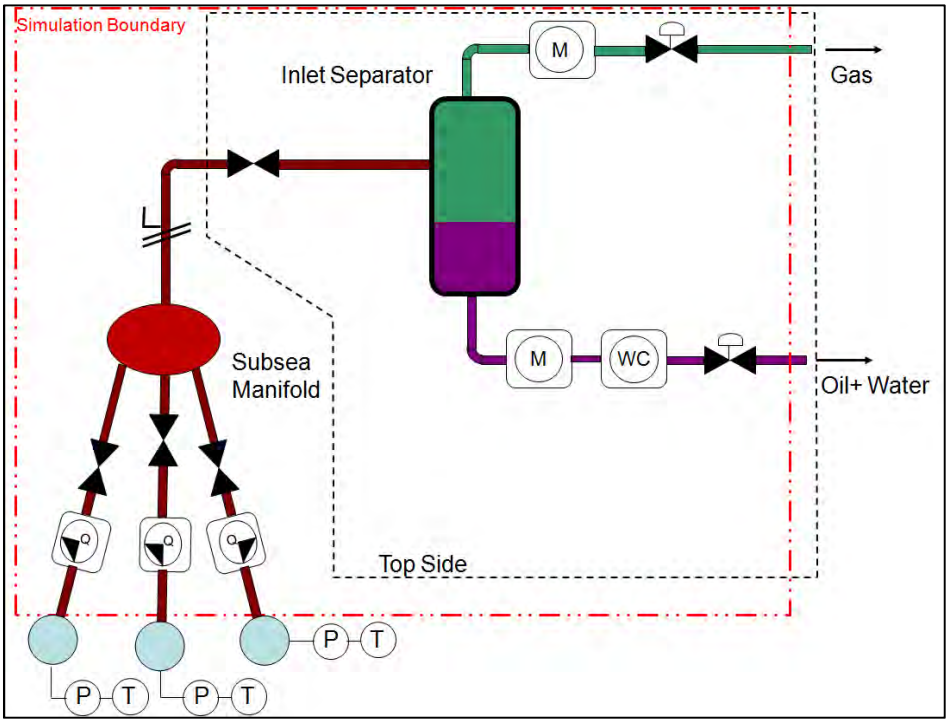

Figure 6. Manifold cluster well arrangement. MPFM at X-tree or PLEM. Two-phase separator at the top side. Gas lift injection into Riser (Optional).

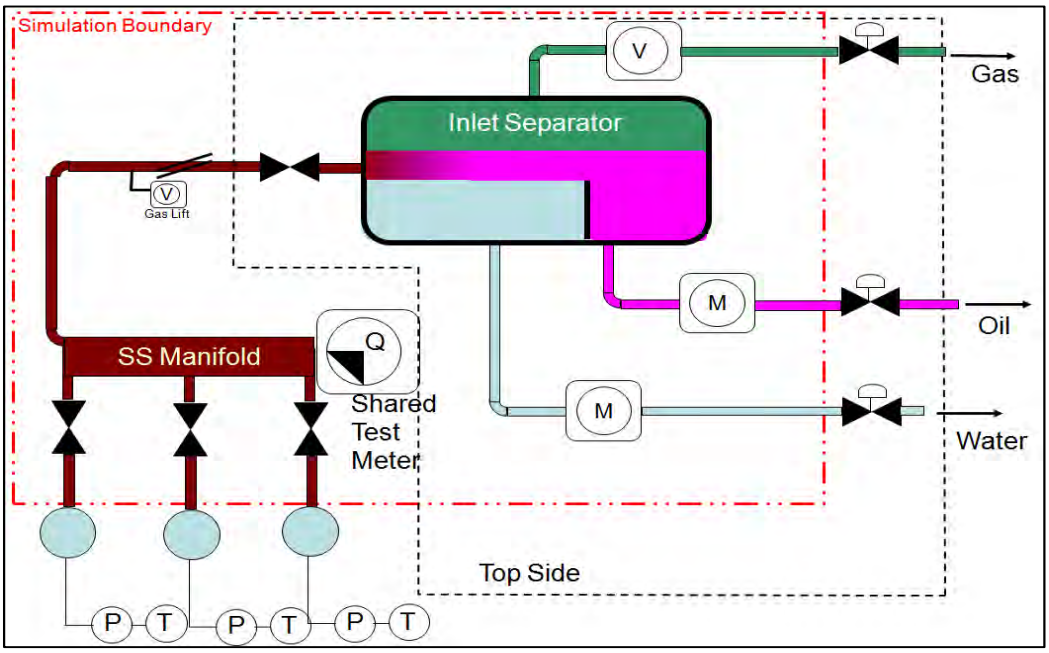

Figure 7. Manifold cluster well arrangement. MPFM installed at Manifold. Two-phase or three-phase separator at topside. Gas lift injection into Riser (Optional).

4.1.3 Required Data

Because of the complexity of the software, a considerable amount of input data is required. Users should be engineers, with a reasonably good understanding of thermodynamics, fluid mechanics and flow measurement. The required input data is listed below.

Well Uncertainty & Separator

- Pressure
- Temperature
- Gas Flow Rate
- Water Flow Rate
- Liquid Level
- Interface Level
- Oil Flow Rate
- Oil Gravity (API)
- Gas Specific Gravity (SGg)
- Water Specific Gravity (SGw)
- Salinity (Y)

Tieback, Jumper, Riser

- Length
- Angle
- Temperature
- Diameter
- Choke characteristics

Uncertainty files

- Multiphase meter
- Single phase meters
- Water cut meter
- GVF meter
- Topside MPFM

4.1.4 Simulation and Reporting Screen Shots

Significant effort was put into creating and testing the interface. The following screen shots show much of the software's Excel interface. They include: field information/well and tieback configuration, meter configuration, separator configuration, and reporting and analysis outputs. A large amount of information is required to setup a case. The program uses help screens and wizards to assist the user wherever possible. Further, an entire case can be saved, edited, and reloaded. If conditions can be assumed approximately the same for different cases, the user can focus on analysis, rather than data gathering. As with any software tool, good user judgment is critical to providing reasonable results.

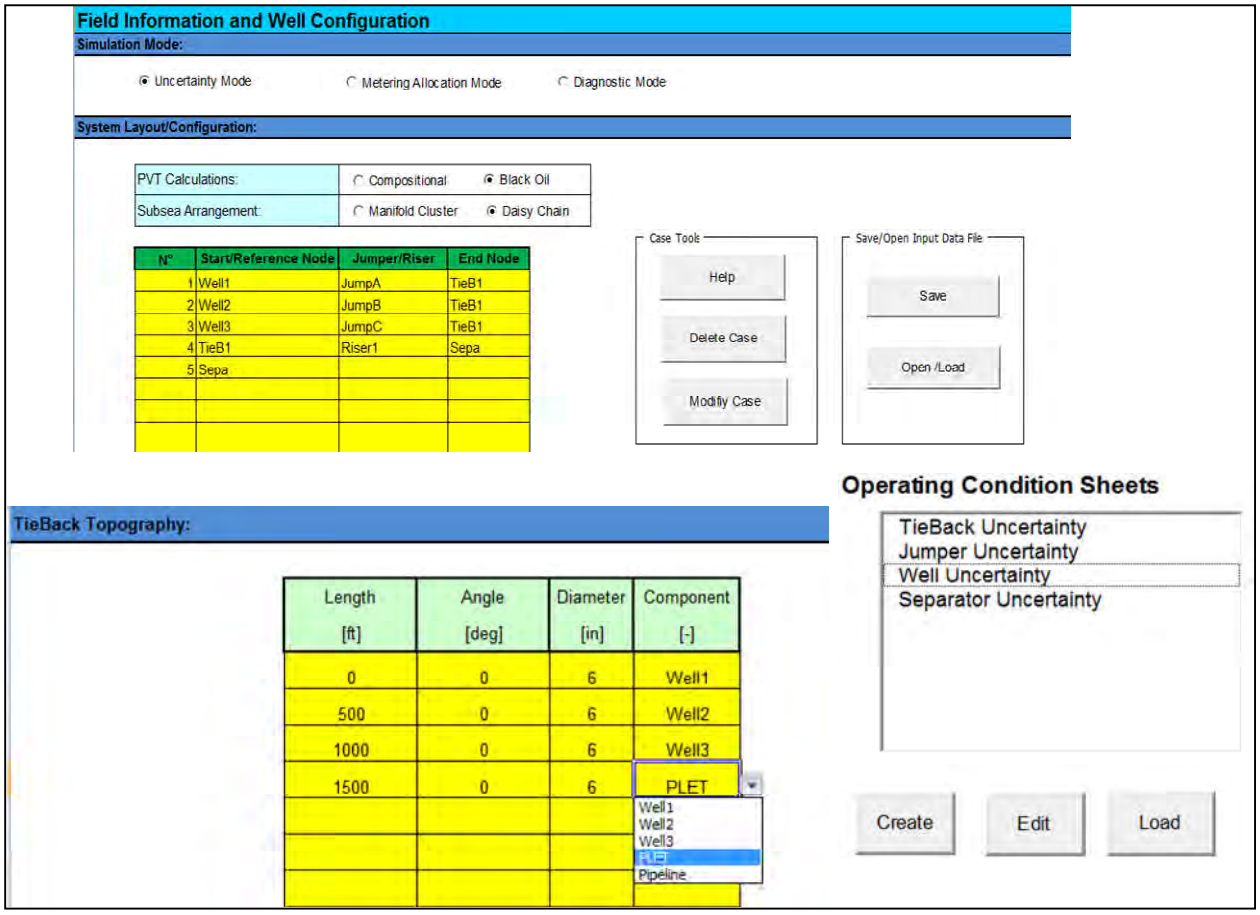

Figure 8. Field information, well and tie back configuration.

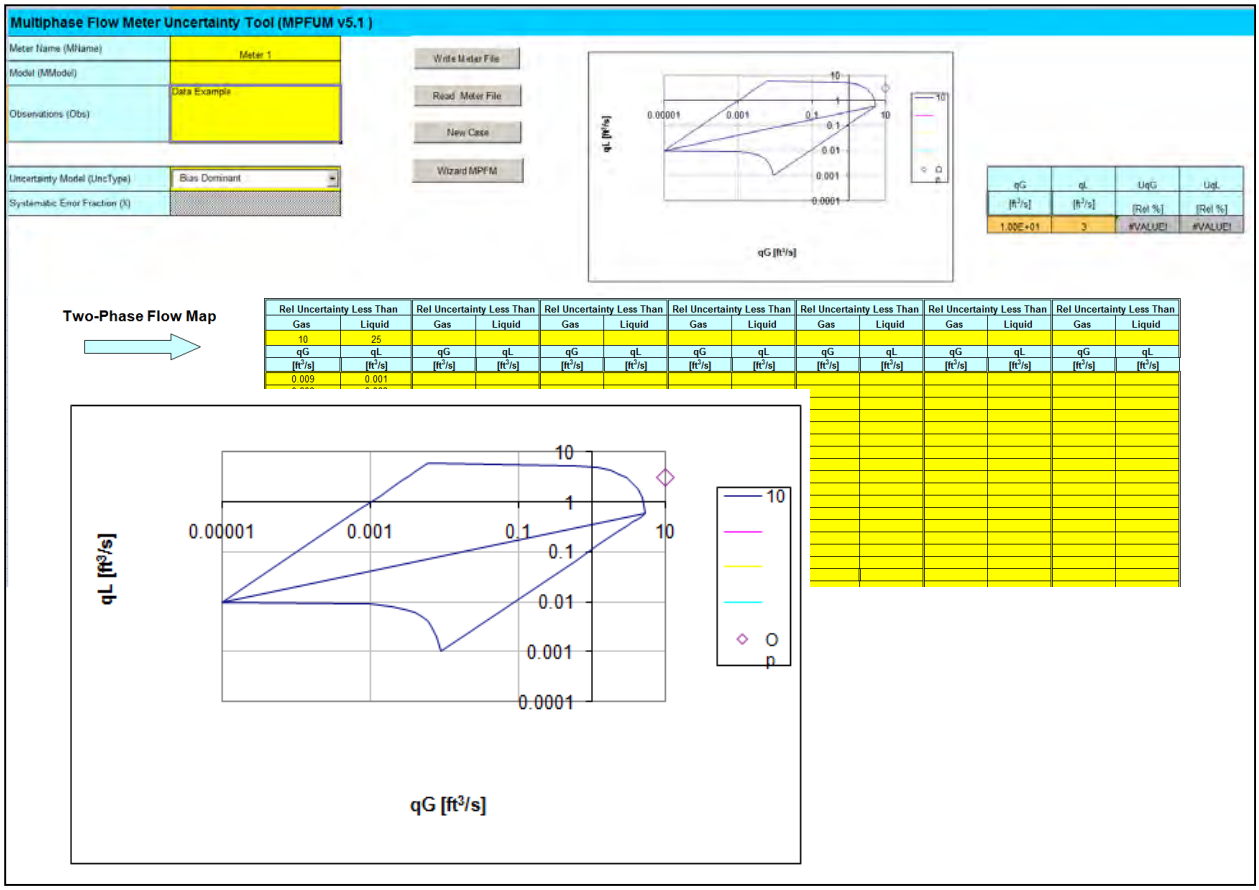

Figure 9. Meter configuration

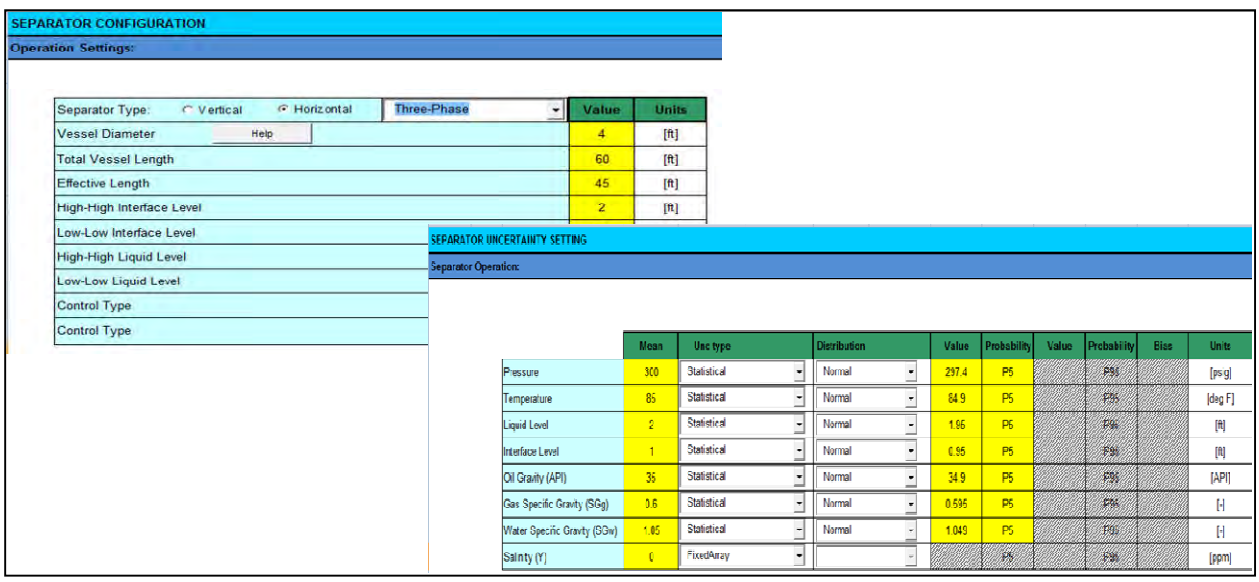

Figure 10. Separator Configuration

Short Report

Lookup Table:

Node Name	Mean Oil Flow Rate	Mean Gas Flow Rate	Mean Water Flow Rate	Warning Flag	Imbalance Flag	Bias Flag	Bias Oil Flow Rate	Bias Gas Flow Rate	Bias Water Flow Rate
	[st bpd]	[scfd]	[st bpd]	[-]	[-]	[-]	[st bpd]	[scfd]	[st bpd]
Well1	3498.99	2507265.75	1871.136				-0.966309	5328.25	21.3811
Well2	3499.868	2489552.25	1849.98				-0.34375	-9268.75	0.108521
Well3	3503.661	2513639.25	1843.053				3.7873535	11489	-7.0769
Sepa	3831.755	3.9729E+11	591.0858				-6668.274	3.973E+11	-4958.66
Imbalance	6670.763	-3.9728E+11	4973.083						

Uncertainty Mode Report

Imbalance Report

Minimum	Maximum	Average	Standard Deviation	Skewness	Kurtosis	Units
					4603468	[st bpd]
					9493482	[st bpd]
					1379266	[scfd]
					0073166	[st bpd]
					5653678	[scfd]
					5229267	[st bpd]

Imbalance Report

MPFM #1 Total Flow rate	MPFM #1 WLR	MPFM #1 GVF	MPFM #1 Oil Flow Rate	MPFM #1 Water Flow Rate	MPFM #1 Gas Flow Rate	MPFM#1 Gas Uncertainty	MPFM#1 Liquid Uncertainty	MPFM#1 WLR/GVF Uncertainty	MPFM#1 Oil Uncertainty	MPFM#1 Water Uncertainty
[ft^3/s]	[-]	[-]	[st bpd]	[st bpd]	[scfd]	[%]	[%]	[abs]	[%]	[%]
1.075029	0.266738	0.604618	3425.019	1886.08	2712426	10.9	5.9	0.034	1.186487	1.076685
1.25911	0.264522	0.637898	3514.881	2060.045	3983028	10.9	5.9	0.034	1.185124	1.076685
1.129336	0.27229	0.612727	3429.436	1404.727	3141916	10.9	5.9	0.034	1.189951	1.076685
0.917188	0.265749	0.558233	3566.606	1416.301	2666662	10.9	5.9	0.034	1.185877	1.076685
0.88995	0.285464	0.538192	3516.313	1842.031	2619857	10.9	5.9	0.034	1.198455	1.076685
1.055333	0.292396	0.583562	3529.566	2362.46	2865270	10.9	5.9	0.034	1.203095	1.076685
1.001612	0.287503	0.566349	3529.351	2094.624	3032075	10.9	5.9	0.034	1.199807	1.076685
1.006948	0.272633	0.584947	3516.472	1440.532	2988453	10.9	5.9	0.034	1.190167	1.076685
0.912911	0.28322	0.544803	3558.138	2124.863	2237547	10.9	5.9	0.034	1.196978	1.076685
0.840084	0.302855	0.52365	3355.084	1558.097	1980136	10.9	5.9	0.034	1.210325	1.076685
0.851342	0.289963	0.517859	3506.932	1965.107	1965519	10.9	5.9	0.034	1.201453	1.076685
1.108243	0.265985	0.605625	3535.326	2229.598	3032623	10.9	5.9	0.034	1.186023	1.076685
0.869176	0.290054	0.529338	3462.121	1823.166	2115118	10.9	5.9	0.034	1.201514	1.076685
0.985377	0.28568	0.570185	3457.968	1488.398	2409533	10.9	5.9	0.034	1.19	
0.867811	0.289846	0.517048	3653.95	1445.183	2221616	10.9	5.9	0.034	1.20	

MPFM #2 Total Flow rate	MPFM #2 WLR	MPFM #2 GVF	MPFM #2 Oil Flow Rate	MPFM #2 Water Flow Rate	MPFM #2 Gas Flow Rate	MPFM#2 Gas Uncertainty	MPFM#2 Liquid Uncertainty	MPF WLR F Unc y
[ft^3/s]	[-]	[-]	[st bpd]	[st bpd]	[scfd]	[%]	[%]	[abs
1.140733	0.277703	0.609395	3495.305	2380.895	2873899	10.9	5.9	
1.002915	0.277107	0.580633	3480.208	2168.767	2888925	10.9	5.9	
1.106834	0.279048	0.603912	3559.041	2322.099	2966327	10.9	5.9	
0.971274	0.276731	0.570625	3462.665	2207.77	2755974	10.9	5.9	
0.88752	0.29623	0.536759	3477.492	1778.22	2381265	10.9	5.9	
0.966649	0.27949	0.567764	3531.285	1796.2	2526076	10.9	5.9	
0.935563	0.311087	0.542707	3506.675	2259.19	2558457	10.9	5.9	
0.919278	0.276674	0.54879	3517.836	1640.849	2526971	10.9	5.9	
1.060859	0.286871	0.59277	3475.534	1996.397	3237797	10.9	5.9	
1.166637	0.264831	0.620154	3609.351	1797.729	3590319	10.9	5.9	
0.913924	0.302508	0.538281	3504.595	2030.155	2683812	10.9	5.9	
1.113716	0.284413	0.604143	3503.58	1815.5	2651023	10.9	5.9	
0.916609	0.2802	0.539853	3616.904	1821.27	2101656	10.9	5.9	

Figure 11. Reporting and Analysis Outputs

4.2 Software Testing

The software was tested at two levels: Developer Testing and User Testing. Developer Testing focused on assessing consistency, repeatability, functionality, operation, and integration. The tests were conducted to assess the software's performance with respect to subroutine functionality, DLL/Excel Integration and Interface performance, handling, and stability. User Testing involved the user's assessment of the software's features, accuracy computation and stability. The full report on the testing of the software may be found at: http://rpsea.letton-hall.com/tiki-download_file.php?fileId=842.

5. Results and Deliverables.

5.1 Software methodology for predicting the flow rate uncertainty for both oil and gas dominant systems.

A software methodology to predict measurement uncertainty for oil and gas dominant systems was developed. The software accounts for subsea multiphase flow meters configured in tiebacks and manifolds, flow line/riser fluid mechanics and thermodynamics, gas lift, separator performance, and single phase meter uncertainty. The background and details of the software methodology can be found at the following link: http://rpsea.letton-hall.com/tiki-download_file.php?fileId=859

5.2 Prediction of the flow characteristics in pipelines as a function of the operational conditions, flow commingling and PVT.

This prediction was incorporated into the software and is performed as an intermediate step in the analysis. With suitable code modifications, the software could report the results of this prediction. This was identified as a future enhancement.

5.3 Prediction of the uncertainty of systems which include multiphase meters, considering the effect of steady state and transient conditions, PVT uncertainties, phase entrainment, separator performance, and meter characteristics.

Once the project was underway, it became apparent that accounting for transient conditions was an unrealistic goal. The successful integration of multiphase meter uncertainty, choke characteristics, fluid flow and thermodynamics in flowlines/risers, gas lift, separator modeling, and single phase flow measurement under steady-state conditions was accomplished, and was a lofty goal itself. Accounting for transient conditions was identified as an area for future work.

5.4 Computer simulator with user-friendly interface. incorporating items 1, 2 and 3, above.

The Excel-based software package can be downloaded at:
http://rpsea.letton-hall.com/tiki-download_file.php?fileId=743

The User Workshop Presentation may be found at:
http://rpsea.letton-hall.com/tiki-download_file.php?fileId=843

The Tutorial for the software may be found at:
http://rpsea.letton-hall.com/tiki-download_file.php?fileId=858

6. Conclusions

6.1 Areas for Continued Development

In this task, a software tool for estimating the uncertainty of subsea multiphase measurement systems was developed and tested. The task successfully demonstrated that uncertainty could be estimated for several common subsea metering system configurations and that a user can compare the estimated uncertainty with expected system variations to determine whether the system is operating as expected. However, as with all software development projects, additional features and capabilities are discovered during the development process. These features cannot always be readily integrated, so they are recorded and targeted for future versions. Desired features and capabilities as identified during this development are listed below.

- Account for transient conditions: As mentioned previously, accounting for the effects of transient conditions was identified as a future goal, given the challenge of developing an integrated uncertainty tool for steady state conditions. The steady state tool will serve well as the starting point for developing a transient model.
- Bias allocation: The current API RP 85 and the other methods available required that the bias is identified and quantified. Even if it is identified, API RP 85 does not include the bias in the allocation process so the method and the program should be modified
- Bias identification and quantification: The current version of UBProdAlloc is able to identify the presence of bias. However, it can only identify bias in the mass balance of a stream (e.g., gas stream). It is not able to determine the error source (which meter has the bias). Available research provides possible methods to narrow down the source or sources of the bias to assist with locating problematic measurements. Coding of these methods is another area for future development.
- Steady State Identification: The allocation process implicitly states that the system must be under steady state (SS) conditions. How can someone say that a system is in SS? We found a very robust theory about data classification that can be utilized to assess the field data. UBProdAlloc can offer an auxiliary program to examine operating data and determine flow consistency over time.

- Allocation based on composition: The allocation process based on flow rate barely satisfies necessary condition for the metering allocation process. One can improve the allocation process by adding the fluid composition in the allocation process. This is particularly important in the gas dominant model. However, it has been left out from the current version and could be added in a next phase.
- Thermodynamics Models: The current version of UBProdAlloc does not include a heat transfer model, so linear temperature profiles are assumed. In the Gulf of Mexico, the heat transfer changes by day and by season. UBProdAlloc should be enhanced so the uncertainty due to heat transfer model can be incorporated.
- Separation: The current model does not consider the effect of separator internal design. Accounting for this may improve the separation efficiency. Such a model can be added to UBProdAlloc in a next phase. Additionally, other types of separators such as a Gas-Liquid Cylindrical Cyclone (GLCC©) separator can also be integrated.
- Availability of flow patterns/flow characteristics as output data.
- Model verification using actual data.

7. References

[1] Cooley, C., Couput, J.-P., Letton, W., and J. Hall, *Wet Gas Allocation on the Canyon Express Project*, North Sea Flow Measurement Workshop, Tonsberg, Norway, October 2003.

[2] American Petroleum Institute (API), Use of Subsea Wet-Gas Flowmeters in Allocation Measurement Systems, Recommended Practice RP 85, March 2003.

[3] Webb, R., Letton W., and M. Basil, *Determination of Measurement Uncertainty for the Purpose of Wet Gas Hydrocarbon Allocation*, 20th North Sea Flow Measurement Workshop, St. Andrew's, Scotland, October 2002.

[4] American Petroleum Institute (API), Measurement of Multiphase Flow, Recommended Practice RP 86, September 2005.

[5] DeepStar Report 8302-2, *Subsea Flow Measurement Uncertainty.*

[6] Multiphase System Integration (MSI), 2005. "Vessel Transient Project Technical Report". TR# 2005-VESSL-TRANS1 R01. Confidential Chevron Report.

[7] Multiphase System Integration (MSI), 2007. "Well Test Measurement System Performance JIP". TR# 2007-WELLTESTJIP1-R01. Confidential Chevron Report.

[8] Mohan, R.S., Pereyra, E.J., Gomez, L. E., and Ting, F.: "Modeling of Well Test Measurement System Performance", Proceedings of the Production and Upstream Flow Measurement Workshop, TUV-NEL Ltd., Houston, TX, 12-14 February 2008.

[9] Multiphase System Integration (MSI) software standards (TR-2007-PROGGUIDE-01 R03), 2007.

Appendix A: Discussion of Budget, Finances.

Area	Budget	Actual
Letton-Hall Group Cost	$144K	$109K
MSI Subcontract	$300K	$312K
Direct Material	$0K	$0K
Testing	$0K	$0K
Consultants	$0K	$0K
Miscellaneous	$18K	$27K
Total	**$462K**	**$448K**

There were no costs in the *Direct Material*, *Testing* or *Consultants* categories. Software testing was conducted as part of the *Letton-Hall Group Costs* and *MSI Subcontract*. *Miscellaneous* includes travel, travel G&A, and subcontractors G&A.

Appendix B: Literature Search

The objective of the literature search was to identify the leading academic organizations (universities and research institutes) and industrial organizations that developed the state of the art in uncertainty analysis. Four keywords were searched using the Engineering Village Search Engine: uncertainty petroleum surface facility, uncertainty separator, uncertainty MPFM, and oil production allocation. A total of 425 papers were found, out of which 278 were published by the Society of Petroleum Engineers (SPE). Consequently, the search was focused on the SPE library. Around 40 relevant publications were identified from the SPE library, as summarized in **Table B.I**. The results of the search were used to narrow the search for uncertainty software tools.

Figure B.1 illustrates the distribution of publications per topic in the database. Many uncertainty publications are found in the literature. Most of these publications address the problem of uncertainty in reservoir simulation, whereas uncertainty analysis for production is a relatively new topic. Probability modeling and decision making are important topics, for which a significant number of papers were published, due to the fact that these are required for risk assessment in the oil industry.

Figure B.2 shows the distribution of publication per university. As can be seen, Stanford University is one of the most prolific sources of publications on the subject. About 25% of the publications on uncertainty come from Stanford. Other important sources are Texas A&M, Imperial College and Heriot-Watt University. This group of universities covers more than 50% of the publications within SPE, regarding the subject addressed.

The distribution of publications per company or professional organization presented in Figure B.3 is more scattered. Although, there is no clear leading company or professional organization in this area, the front runner companies are BP, Chevron, and Schlumberger.

Table B.I. Literature Review Database

Title	Authors	Published by	Topic	Keyword	Relevance	Date
Dynamic Data Integration and Quantification of Prediction Uncertainty Using Statistical Moment Equations	P. Likanapaisal; L. Li; H.A. Tchelepi	SPE 119138	probabilistic model	probabilistic model; history matching; reservoir simulation ;dynamic data; Monte Carlo simulation	5	2009
Handling Production-Data Uncertainty in History Matching: The Meren Reservoir Case Study	C.S. Kabir; N.J. Young	SPE 87823	probabilistic model	probabilistic model; history matching; reservoir simulation ;production uncertainty; Monte Carlo simulation	5	2004
History Matching With Production Uncertainty Eases Transition into Prediction	A.J. Little;H.A. Jutila;A. Fincham	SPE 100206	allocation	allocation; history matching; reservoir simulation ;production allocation; Bayesian	5	2006
Application of Fuzzy Logic for Determining Production Allocation in Commingle Production Wells	B. Widarsono and H. Atmoko, Lemigas; W. Robinson IV and I.P. Yuwono, PT CPI; F. Saptono, Tunggal; Ridwan, Lemigas	SPE 93275	allocation	allocation; commingle wells; fuzzy logic;;	5	2005
Improving the Quality of Production Data and Its Effect on Allocation Factor and Reserves Estimation	B. Ghaempanah; P. Mehdizadeh; S.L. Scott	SPE 103319	uncertainty	uncertainty; reservoir simulation; production uncertainty; Monte Carlo Simulation; well testing	5	2006

Title	Authors	Published by	Topic	Keyword	Relevance	Date
Metering of High-Vapor-Pressure Crude Oils: The Case for Mass Measurement in Shared Pipeline Systems	R.C. Gold; S.G. Simmons,	JOURNAL OF PETROLEUM TECHNOLOGY	allocation	allocation; commingled wells; composition	5	1984
Multiphase Flowmeter Application for Well and Fiscal Allocation	B. C. Theuveny; Parviz Mehdizadeh	SPE 76766	allocation	allocation; multiphase flowmeters ;uncertainty; fiscal allocation	5	2002
Probabilistic Field Development in Presence of Uncertainty	Sara Passone; Gregory J. McRae;	SPE 11294	uncertainty	uncertainty ;decision making; bayesian ;optimization; Monte Carlo	5	2007
Rate Allocation using Permanent Downhole Pressures	M. McCracken and D. Chorneyko	SPE 103222	allocation	allocation; commingle wells; downhole pressure;	5	2006
The Quality Map: A Tool for Reservoir Uncertainty Quantification and Decision Making	Paulo S. da Cruz; Roland N. Horne; Clayton V. Deutsch	Journal of Petroleum Technology	uncertainty quantification	uncertainty quantification; decision making; stochastic models; quality map;	5	2004
Adapting Probabilistic Methods To Conform to Regulatory Guidelines	Herman G. Acun, and D.R. Harrell,	SPE 78675	probabilistic models	probabilistic models; reserve evaluation;	4	2002

Title	Authors	Published by	Topic	Keyword	Relevance	Date
Added Value of a Multiphase Flowmeter in Exploration Well Testing	E.A. Mus; E.D. Toskey; S.J.F. Bascoul; R.J. Norris	SPE 80283	Multiphase Flowmeter	Multiphase Flowmeter ;well test separator ;well testing;	4	2002
Best Practices and Methods on Hydrocarbon Resource Estimation, Production and Emissions Forecasting, Uncertainty Evaluation, and Decision Making	R.M. Jonkman, C.F.M. Bos, J.N. Breunese; D.T.K. Morgan; J.A. Spencer; E. Søndenå	SPE 77280	decision making	decision making; uncertainty evaluation; well testing;reserve estimation; production forecasting	4	2002
Characterizing Uncertainty for Oil and Gas Evaluations	Robert H. Caldwell; David I. Heather	SPE 68592	uncertainty	uncertainty ;reserve estimation; uncertainty characterization; probabilistic model;	4	2001
Comparison of Stochastic Sampling Algorithms for Uncertainty Quantification	L. Mohamed; M. Christie; V. Demyanov	SPE 119139	uncertainty	uncertainty ;bayesian approach; reservoir simulation ; Monte Carlo; Markov Chain	4	2009
Monte Carlo Simulation of Vertical-Separators in a Network of Intermittent Gas Lift Wells	Sergio Caicedo; Militza Trujillo; Horacio Florez	SPE 89646	Monte Carlo	Monte Carlo; intermittent gas lifted ;slug flow;	4	2006
Multi-objective Optimization with Application to Model Validation and Uncertainty Quantification	Ralf Schulze-Riegert; Markus Krosche; Abul Fahimuddin; Shawket Ghedan	SPE 105313	history matching	history matching; reservoir simulation; uncertainty quantification;	4	2007

Title	Authors	Published by	Topic	Keyword	Relevance	Date
Probability Models for Petroleum Investment Decisions	Marvin Smith	SPE 2587	probability theory	probability theory; decision making; stochastic model; risk;	4	1970
Quantification of Production Prediction Uncertainty and its Impact on the Management of Oil and Gas Price Risk	R.A. Edwards and T.A. Hewett	SPE 28330	uncertainty quantification	uncertainty quantification; reserve evaluation; risk; oil gas properties; stochastic model	4	1994
A New Streamline Method for Evaluating Uncertainty for Small-Scale, Two-Phase Flow Properties	J.J. Hastings, A.H. Muggeridge, and M.J. Blunt,	SPE 83671	Streamlines	Streamlines; permeability ;porosity; scaling ;stochastic model	3	2003
A New Tool To Evaluate the Feasibility of Petroleum Exploration Projects using a Combination of Deterministic and Probabilistic Methods	Mohammed Siddiqui; Karam Al-Yateem; and Abdulla Al-Thawadi	SPE 105694	Uncertainty	Uncertainty; probabilistic model; decision making; Monte Carlo simulation; stochastic model	3	2007
Predicting the Viscosity of Hydrocarbon Liquid Phases based on Composition	A, H. Houpeurt; M. B. Thelliez	SPE 5057	viscosity	viscosity ;accuracy ;	3	1976
Price Uncertainty Quantification Models Advance Project Economic Evaluations	G.T. Olsen; F.L. Fariyibi; W.J. Lee; D.A. McVay	SPE 94610	uncertainty	uncertainty ;price forecast ;Gaussian simulation;	3	2005

Title	Authors	Published by	Topic	Keyword	Relevance	Date
The API/GPA Orifice-Plate Data Base	Wayne A. Fling .Jr	Journal of Petroleum Technology	orifice plate	orifice plate; natural gas;	3	1988
Two-Phase Flow Splitting at a Pipe Tee	K. C. Hong,	Journal of Petroleum Technology	splitting	splitting; pipe network;	3	1978
Uncertainty Assessment of Well Placement Optimization	Barıs. Guyag uler; Roland N. Horne	SPE 71625	uncertainty	uncertainty; forecast model; decision making;	3	2001
A Large-Scale Planning and Evaluation Tool for Upstream Oil and Gas operations	Blackburn, CR	SPE 18934	decision making	decision making; Economic Analysis; APEX; Capital Allocation; Strategic planning	2	1989
A Probabilistic Approach to Shale Gas Economics	William M. Gray, Troy A. Hoefer, ,Andrea Chiappe, Victor H. Koosh,	SPE 108053	Gas Economics	Gas Economics; uncertainty;economic feasibility; shale ;	2	2007
A Review of Marine Systems Use in Developing Alaskan Natural Gas	Hederman, W . F	SPE 11294	pipelines	pipelines; natural gas;	2	2007

Title	Authors	Published by	Topic	Keyword	Relevance	Date
Holistic vs. Hole-Istic E&P Strategies	B.C. Ball Jr; S.L. Savage	SPE 57701	uncertainty	uncertainty; decision making;	2	1999
Integrated Modeling of the El Furrial Field Asset Applying Risk and Uncertainty Analysis for the Decision Making	L.M. Acosta, J. Jiménez, A. Guedez, E.A. Ledezma, J.A. Bello, A.J. Millán, M. Guzman, and E. Marin; F.J. Gómez, and I. Herrera; and P. Córdoba,	SPE 94093	decision making	decision making; probabilistic model;	2	2005
Managing Risk and Uncertainty in the Visualization of Production Scenarios	L. Saputelli,;G. Mijares; J.A. Rodriguez;S. Sankaran; L. Garibaldi; K. Revana; F.J. Gómez, and I. Herrera; and P. Córdoba,	SPE 68579	decision making	decision making; uncertainty;	2	2007
Managing Risks using Integrated Production Models: Applications	C.V. Chow, M.C. Arnondin, K.D. Wolcott, and N.D. Ballard	SPE 57473	decision making	decision making; risk;	2	2000

Title	Authors	Published by	Topic	Keyword	Relevance	Date
Offshore Chemical EOR: The Role of an Innovative Laboratory Program in Managing Uncertainty Results to Ensure the Success of a Pilot Field Implementation	Suzalina Zainal; Arif Azhan A. Manap,; Pauziyah A. Hamid; Mohamad Othman; Mizan Omar Chong; A. Wafi Yahya; Nasir Darman; Rithauddin M. Sai	SPE 113154	uncertainty	uncertainty ;lab test; EOR;	2	2008
Modeling Low-Salinity Waterflooding	Gary R. Jerauld; C.Y. Lin, Kevin J. Webb; Jim C. Seccombe	SPE 102239	Waterflooding	Waterflooding	1	2008
Vorticity-Based PEBI Grids for Improved Upscaling of Two Phase Flow	M. Evazi, H. Mahani; K. Hejranfar; M. Masihi	SPE 113703	reservoir simulation	reservoir simulation; scale; geological models;	1	2008
Optimizing Reservoir Performance Under Uncertainty with Application to Well Location	S.1. Aanonsen,;A.L. Eide; L. Holden; J.O. Aasen	SPE 30710	uncertainty	uncertainty ;reservoir simulation; geological uncertainties; well locations ;	4	1995

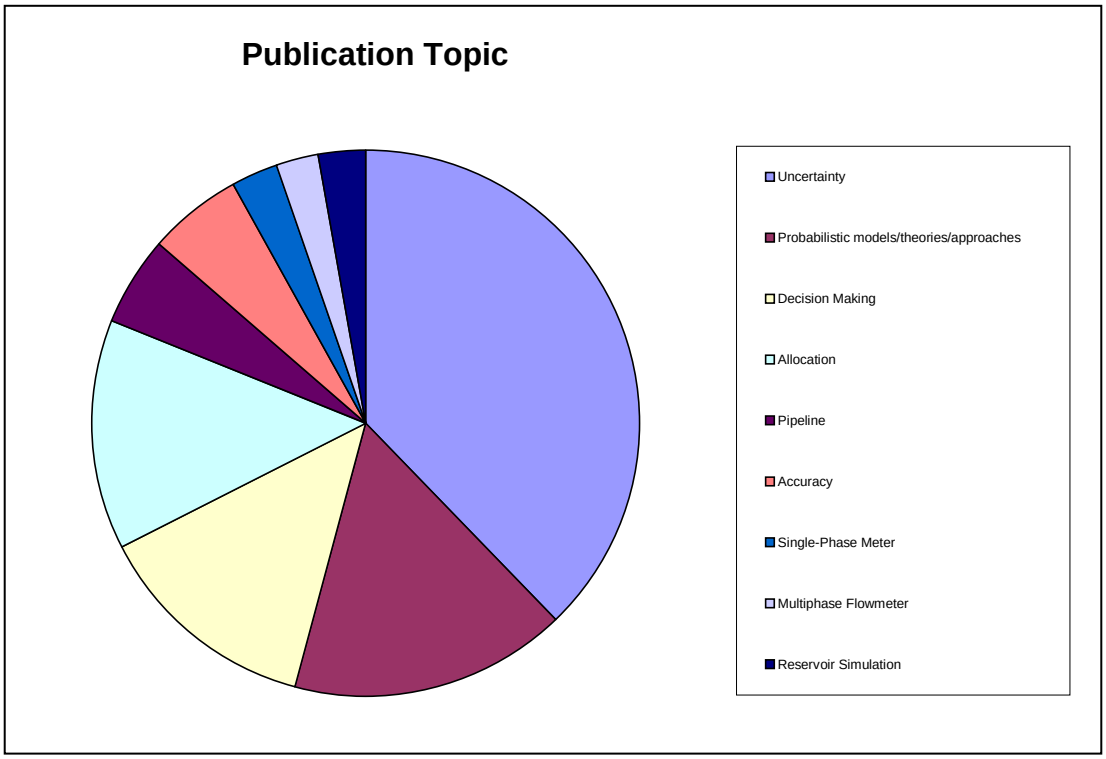

Figure B.1. Contribution of Main Topics to Collected Database

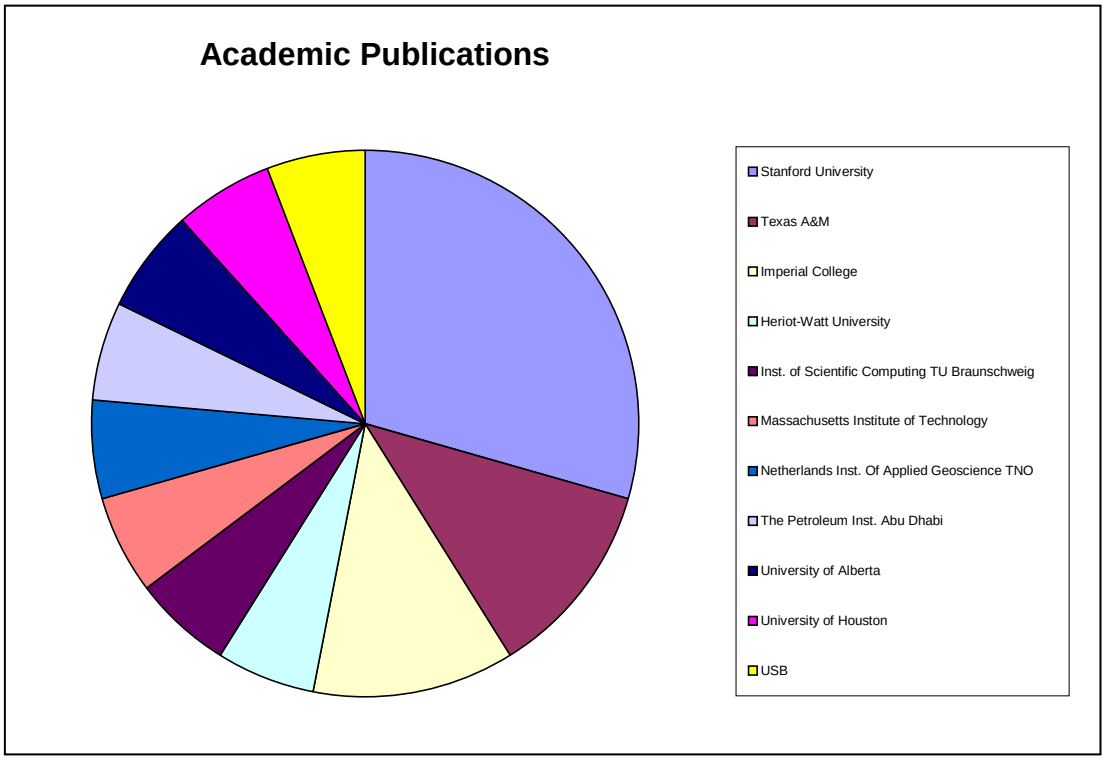

Figure B.2. Contribution of Academic Publications to Collected Database

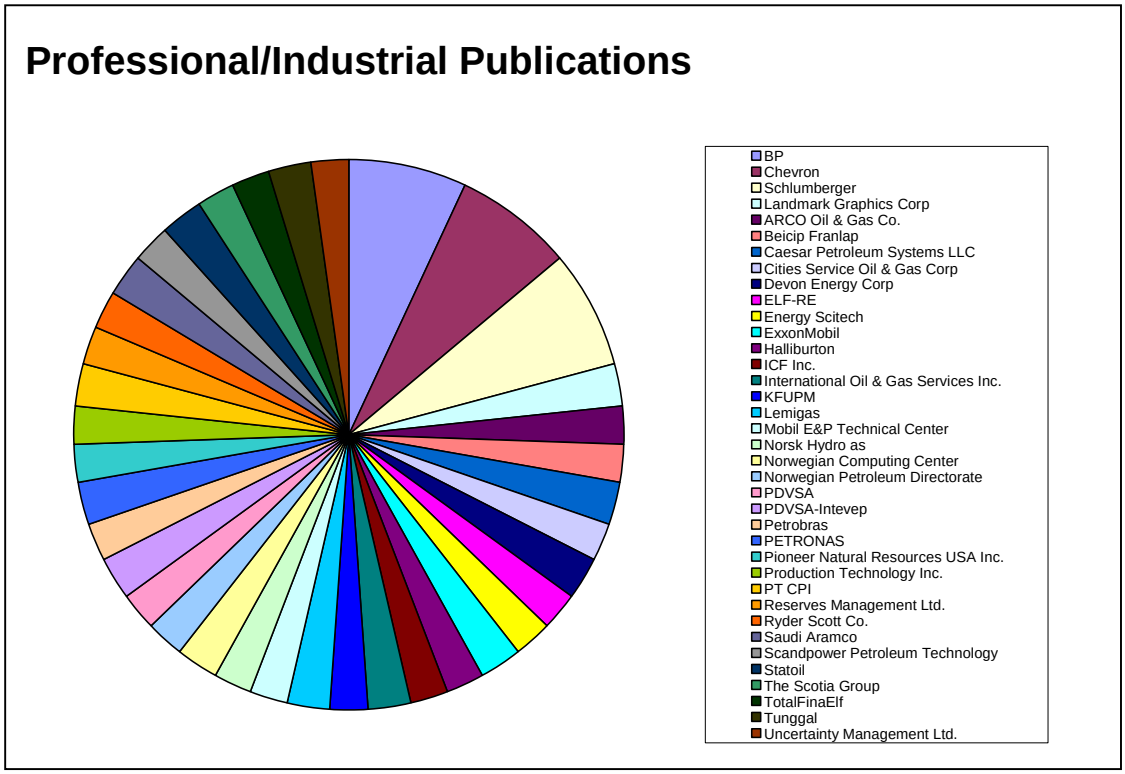

Figure B.3. Contribution of Professional or Industrial Publications to Collected Database

Appendix C: Uncertainty Analysis Software Search

A review of available uncertainty analysis software was conducted to identify tools that might have assisted in the development of UBProdAlloc. Results from the literature search were used to guide the uncertainty analysis software search. The search included academic and professional organizations with ties to the oil industry, industries other than oil and gas, and tools providing general uncertainty analysis capabilities.

Oil Industry - Academic and Professional Organizations

Academic Organizations

The review looked at academic institutions conducting research and development (R&D) for the oil and gas industry, as well as other universities, which do not conduct R&D for the oil and gas industry, but have developed software or tools for uncertainty analysis.

Three sources of information were utilized, namely, web-search tools (e.g., Google), direct contact with university personnel, and searches within the Tulsa University web server. The goal was to determine the availability within academia of uncertainty software tools either fully implemented or under development, which allow computing the uncertainties associated with oil production installations. Some of these institutions developed software applicable to reservoir simulation, or uncertainty analysis for financial risk assessment. None had software tools to assess the uncertainties associated with upstream production installations. Stanford University, Texas A&M, Imperial College, and Heriot-Watt University were identified as the leading institutions on uncertainty analysis for the oil industry.

<u>Stanford University</u>

Stanford University includes the Systems Optimization Laboratory (SOL), within the Dept. of Management Science and Engineering. The SOL conducts basic and applied research on large-scale mathematical programming, including development of algorithms, model formulation, and software production. One of the main research areas is Stochastic Linear Programming (Planning Under Uncertainty). Several optimization software codes have been developed. However, no specific software for computing uncertainty analysis or

allocation was found, despite several papers published in this area. More information about this group and available software can be found at the website listed below.

Contact Info:

http://www.stanford.edu/group/SOL/

No software or tools for uncertainty analysis, characterization or quantification were found from the Department of Energy Resources Engineering at Stanford University either.

Department of Energy Resources Engineering

http://ekofisk.stanford.edu/

Professor Roland N. Horne, Phone: 650-723-4744, Fax: 650-725-2099,

Email: peteng@pangea.stanford.edu.

Texas A&M

The specific areas of research within the Petroleum Engineering Department at Texas A&M include: gas reservoirs, coalbed-methane reservoirs, hydrate reservoirs, naturally fractured reservoirs, heavy oil, high-pressure/high-temperature operations, smart well technology, drilling, well construction, production technology, well stimulation, reservoir visualization, reservoir simulation, resource assessments, quality mapping, formation evaluation, enhanced recovery, reservoir performance, and environmental and water issues. No software for uncertainty characterization/analysis was found published by this department.

Contact Info:

Harold Vance Department of Petroleum Engineering

http://www.tamu.edu/

Darla-Jean Weatherford, Lecturer/Information Representative, Phone: 979-845-2205, Fax: 979-845-1307

Email: darla-jean@tamu.edu.

Imperial College

The research carried out by the Department of Earth Science and Engineering at Imperial College has been focused on studying the effect of uncertainty in production forecasting and control techniques for smart wells. In production forecasting, the goal is to promote the study called PUNQ-S3 (production forecasting with uncertainty quantification). Regarding control techniques for smart wells, the goal is to understand the role of well optimization subject to uncertainty, especially in those cases where the production varies quickly as a function of time. In either case, an uncertainty software tool could not be found published by this university.

On the other hand, several research projects have been conducted in the Environmental and Water Resource Engineering Department, regarding model uncertainty quantification. This department published studies on a Monte Carlo Analysis Tool, which is a collection of MATLAB analysis and visualization functions integrated through a graphical user interface. This tool can be used to analyze the results from Monte Carlo model simulations or from optimization methods, which are based on parameter sampling techniques, providing insight into the structure and sensitivity of mathematical models, and uncertainty estimate of model outputs.

Contact Info:

Director of the Centre for Petroleum Studies, Department of Earth Science and Engineering

http://www.imperial.ac.uk/ese

Alain Gringarten, Professor of Petroleum Engineering, Phone: 44 20 7594 7440, Fax: 44 20 7594 7444

Email: a.gringarten@imperial.ac.uk.

Heriot-Watt University

The uncertainty quantification group of the Petroleum Engineering Department at Heriot-Watt Institute conducts research on uncertainty propagation in reservoir modeling. This group has not developed any software tool, but they conducted and applied research on the subject. One of the key goals of the project is to develop techniques to quantify the

confidence level in uncertainty predictions. The accuracy of the prediction depends on many assumptions made in the simulation and in the assessment of the quality of the match. This group is developing statistical error models to improve the reliability of parameter estimation.

Contact Info:
http://www.pet.hw.ac.uk/research-projects/uncertainty/index.cfm

University of Texas at Austin

This university has a Center on Predictive Engineering and Computational Sciences (PECOS), which is a U.S. Department of Energy funded Center of Excellence within the Institute for Computational Engineering and Sciences. PECOS brings together an interdisciplinary, multi-university team, which has strong ties with the DOE National Labs and NASA. The goal of the PECOS Center is to develop the next generation of advanced computational methods for predictive simulation of multiscale, multiphysics phenomena, and to apply these methods to the problem of reentry of vehicles into the atmosphere. One of the objectives of PECOS is to develop tools, along with the required mathematical models, to quantify the uncertainties inherent in such models. However, no other information about available tools or software for uncertainty analysis published by this center, nor from the Petroleum & Geosystems Engineering Department was found.

Contact Info:
PECOS
http://www.ices.utexas.edu/centers/pecos/
Director: Robert Moser – ICES and Department of Mechanical Engineering
Contact person: Fatima Bridgewater
Email: fatima@ices.utexas.edu, Phone: 512-471-3168

Petroleum & Geosystems Engineering Department
http://www.cpge.utexas.edu/
Gary A. Pope, CPGE Director, Phone: 512-471-3235, Fax: 512-471-1006;
Email: gpope@mail.utexas.edu.

The University of Tulsa

The Petroleum Engineering Department at the University of Tulsa has several ongoing research consortia in the areas of Artificial Lift, Two-Phase Flow and Multi-Phase Flow, Flow Assurance, Paraffin Deposition, Hydrates Formation, Reservoir Engineering, Compact Separators, Drilling Engineering and Automatic History Matching. Among the ongoing research consortia the Tulsa University Petroleum Reservoir Exploitation Projects (TUPREP) focuses on Quantification of Uncertainty in Reservoir Description and Performance Predictions, Characterization of Measurement Error in Production and Seismic Data, and Field Applications of Automatic History Matching and Stochastic Optimization for Automatic History Matching, among others. No specific software or tool for uncertainty quantification/analysis has been developed by this consortium.

The Tulsa University Separation Technology Project (TUSTP) research consortium has developed specific software tools for measurement uncertainty analysis based on standard uncertainty analysis protocol proposed by NIST (National Institute of Standards and Technology) and modeling uncertainty analysis based on Monte Carlo methods.

Contact Info:

Tulsa University Petroleum Engineering Department:
Loreta Watkins, Department Assistant II, Phone: 918-631-2533, Fax: 918-631-2059,
Email: loreta-watkins@utulsa.edu

Tulsa University Petroleum Reservoir Exploitation Projects (TUPREP):
http://www.tuprep.utulsa.edu
Dr. Albert C. Reynolds, Phone: 918-631-3043, Fax: 918-631-2059,
Email: reynolds@utulsa.edu.

Tulsa University Separation Technology Projects (TUSTP):
http://www.tustp.org
Dr. Ovadia Shoham, Phone: 918-631-3255, Fax: 918-631-2059, Email: os@utulsa.edu.
Dr. Ram S. Mohan, Phone: 918-631-2075, Fax: 918-631-2093,
Email: ram-mohan@utulsa.edu.

Texas Tech University

A search of the research areas of the Petroleum Engineering Department at Texas Tech University was carried out. However, no software for uncertainty characterization/analysis was found.

Contact Info:

Petroleum Engineering Department
Phone: 806-742-3573, Voicemail: 806-742-1801, Fax: 806-742-3502,
Email: joan.blackmon@ttu.edu

Other relevant academic organizations conducting R&D on oil and gas industry listed in the SPE directory (http://www.spe.org/spe-app/spe/industry/ps/rd_providers_dir.htm) are summarized in **Table C.I**. No software or tools for uncertainty analysis, characterization or quantification published by these organizations were found.

Table C.I. Other Academia Organizations Listed in SPE Directory

Name	Areas of Research	Contact Info
Colorado School of Mines	Petroleum economics Risk analysis Phase behavior Enhanced oil recovery Coal-bed methane Drilling, completion, and workover operations and engineering Reservoir modeling Numerical simulation Rock mechanics Pressure transient analysis Stimulation engineering Hydraulic fracturing Multidisciplinary team research Natural gas engineering	Petroleum Engineering Department http://www.mines.edu/academic/petroleum/index.htm Head Professor and Interim Department: Ramona Graves, , Phone: 303-273-3740, Fax: 303-273-3189, Email: rgraves@mines.edu
Louisiana State University	Drilling engineering, Production engineering, Reservoir engineering, Reservoir characterization, Environmental aspects of Petroleum Engineering, Petrophysics, Petroleum economics, Well control, Well design, Well logging, Under-balanced drilling, Fluid-jet drilling, Applied mathematics and computer programming, and Improved gas and oil recovery	Craft and Hawkins Department of Petroleum Engineering http://www.pete.lsu.edu/ John Rogers Smith, Associate Professor, Phone: 225-578-0412, Fax: 225-578-6039, Email: jsmith5@lsu.edu
University of Kansas, TORP	EOR/IOR, polymer flooding, carbon dioxide miscible and near miscible flooding, thermal recovery, waterflooding, gelled polymers, reservoir management, reservoir simulation, water shutoff, conformance control in both fractured and unfractured reservoirs, CO2 sequestration, phase behavior and minimum miscibility research, field demonstration projects, reservoir characterization, production engineering, operations management, environmental engineering, drilling engineering, technology transfer	http://www.torp.ku.edu G. Paul Willhite, CoDirector, Phone: 785-864-2906 Fax: 785-864-4967, Email: willhite@ku.edu

Other academic organizations, that do not have a Petroleum Engineering Department, but have developed software or tools for uncertainty analysis are presented next.

Lancaster University – GLUE

This is a package that provides tools for sensitivity analysis and uncertainty estimation using the results obtained from Monte Carlo simulations. The GLUE concept is a rejection of the concept of setting an optimum parameter, claiming that it is only possible to evaluate the relative performance of available models, either qualitatively or quantitatively in terms of some likelihood measure.

The predictions of the Monte Carlo realizations are weighted by the likelihood measures to determine the prediction limits of the required variables. Thus, those parameter set realizations that perform well in the evaluation are given the greatest weight in the prediction.

The GLUE methodology focuses on the subjective nature of model evaluation (e.g., choice of likelihood measure, choice of threshold value), but requires that those elements be defined explicitly and therefore made open to debate and justification. Parameter interactions and nonlinearity in the model responses (which may be extremely complex and potentially even chaotic) are handled implicitly by the GLUE methodology. In essence, the nonlinear response of a particular model parameter set is summarized by the associated likelihood value. Thus, the analysis focuses on parameter sets rather than the behavior of individual parameters and the interactions among them.

Contact Info:
http://domino.lancs.ac.uk/Info/lunews.nsf/I/BA7F9E4665A74F638025727D0057C4B4

University of Bristol - Perimeta Software Tool

Perimeta (performance through intelligent management) is a software tool that has been developed to support evidence based on uncertainty analysis results. This software tool represents the system being modeled utilizing hierarchal uncertainty strategies. Each process may have a sub-graph of argumentation node. At any point evidence representing the belief in the node's statement can be entered, directly or indirectly. This software conducts hierarchical uncertainty; thus, the relationship among the 'block' or 'model' must

be clearly defined. Perimeta is a windows-based application written in C++. This application is available only to the members of the research consortium.

Contact Info:

Dr John Davis, Reader in Engineering Systems, Civil Engineering Systems, Coastal Engineering, Field Monitoring, Fluid Mechanics, Phone: (0117) 928 7712 - Internal 87712, Department Fax: (0117) 928 7783 - Internal 7783
http://www.bristol.ac.uk/civilengineering/research/systems/projects/perimeta.html
Email: john.davis@bristol.ac.uk.

North Carolina State University - AuvTool

This software conducts statistical analysis of variability and uncertainty associated with fitting distributions to data sets for use with the Stochastic Human Exposure Dose Simulations modeling framework. It is also generally applicable for quantifying variability and uncertainty of data sets used for risk assessment, emissions estimation and other quantitative analysis fields.

This tool features the use of bootstrap simulation and two-dimensional Monte Carlo simulations for simultaneously quantifying variability and uncertainty. Object-oriented programming techniques are applied to the development of the software tool.

Contact Info:

http://www.ce.ncsu.edu/
H. Christopher Frey, Professor, Department of Civil, Construction, and Environmental Engineering, North Carolina State University, Phone: 919 515-1155, Fax: 919-515-7908
E-mail: frey@eos.ncsu.edu.

Delft University - UNICORN

UNICORN is a stand alone, windows-based application, uncertainty analysis software package (uncertainty analysis with correlations), whose main focus is on dependence modeling for high dimensional distributions. Random variables can be coupled using a number of dependence structures (such as dependence trees, vines, Bayesian belief nets). An extended formula parser is available for defining the model output, as are a number of

post-processing options, such as report generation, various graphical interpretations, conditioning, sensitivity analysis and probabilistic inversion.

Contact Info:

Delft Institute of Applied Mathematics, Delft University of Technology - Risk and Environmental Modeling – UNICORN Software
http://ewi.tudelft.nl/index.php?id=23160&L=0
Dr. Dorota Kurowicka, Phone: +31 -(0)15 - 278 1635, Fax: +31- (0)15 - 278 7255, Email: d.kurowicka@ewi.tudelft.nl.

Professional Organizations

This section presents a brief description of some professional research organizations for the oil and gas industry, which were identified in this study. The professional organizations include SPE, ASME, and ISO, among others. The search was conducted utilizing web search engines, utilizing the keywords: "uncertainty software tool", "uncertainty tool" and "uncertainty software".

Sandia National Laboratory- DAKOTA

DAKOTA (Design Analysis Kit for Optimization and Terascale Applications) is a toolkit that contains algorithms for optimization with gradient and nongradient-based methods; uncertainty quantification with sampling, reliability, stochastic expansion, and epistemic methods, parameter estimation with nonlinear least squares methods, and sensitivity/variance analysis with design of experiments and parameter study methods.

These capabilities may be used on their own or as components within advanced strategies such as hybrid optimization, surrogate-based optimization, mixed integer nonlinear programming, or optimization under uncertainty.

The DAKOTA toolkit provides a flexible and extensible problem-solving environment for design and performance analysis of computational models on high-performance computers Written in C++, the DAKOTA tool is intended as a flexible, extensible interface between simulation codes and a variety of iterative systems analysis methods. These include:

optimization, uncertainty quantification, nonlinear least squares methods, and sensitivity/variance analysis.

Contact Info:

http://dakota.sandia.gov/software.html

David Borns, Manager, Geotechnology & Engineering, Phone: 505- 844-7433, Fax: 505- 844-0240, Email: djborns@sandia.gov.

Unit of Econometrics and Applied Statistics of the Joint Research Centre - SIMLAB

This is a Windows-based application that provides a free development framework for sensitivity and uncertainty analyses. SimLab is a professional tool for model developers, scientists and professionals for applying uncertainty and sensitivity analysis techniques. SimLab provides a reference implementation of the various available uncertainty and sensitivity analysis techniques. This program is an ongoing project where new improvements have progressed on a regular basis since 1985. The code is released as a desktop application, but recent versions provide a development environment for uncertainty and sensitivity analysis without a graphical user interface, which supports a set of coding techniques, such as C, C++, Matlab, and Fortran.

Contact Info:

http://simlab.jrc.ec.europa.eu/

Natural Environment Research Council - GEM-SA

The Gaussian Emulation Machine for Sensitivity Analysis (GEM-SA) software aims to provide user-friendly tools to implement statistical analyses of uncertainty in the outputs of computer models, using Gaussian process emulation techniques. The GEM software has been developed by Marc Kennedy for the Centre for Terrestrial Carbon Dynamics (CTCD). CTCD is funded by the Natural Environment Research Council (NERC). The Gaussian Emulation Machine for Sensitivity Analysis (GEM-SA) allows building an emulator of a computer code from a set of input and output points. It also performs prediction, uncertainty analysis and sensitivity analysis of the code using far fewer code runs than Monte-Carlo-based methods.

GEM-SA is offered free of charge, provided it is not used for profit. It may be freely copied and distributed, provided that files have not been edited or altered in any way, and also that no charge is made for distributing GEM-SA. GEM-SA runs on Windows, but Linux users can also run it.

Contact Info:
http://www.tonyohagan.co.uk/academic/GEM/index.html

Other relevant professional research organizations for the oil and gas industry listed in the SPE directory (http://www.spe.org/spe-app/spe/industry/ps/rd_providers_dir.htm) are presented in **Table C.II**. For these organizations, no software or tools for uncertainty analysis, characterization, or quantification was found.

Natural Gas Industry tools such as the Bureau of Land Management Uncertainty (http://www.ceesi.com/UncertaintyCalculator.aspx) tool for natural gas meters and the Pipeline Research Council International Uncertainty tool (http://prci.org/index.php/site/projects_single/meter_station_uncertainty_analysis_tool/) were briefly reviewed and dismissed from consideration because they focus on single phase natural gas and do not attempt to include complete measurement systems (i.e., They focus on one or more meters without consideration of the surrounding piping system or fluid mechanics/thermodynamics.).

Table C.II. Other Research Organizations Listed in SPE Directory

Name	Areas of Research	Contact Info
C-FER Technologies (Canada)	Downhole Equipment, Artificial Lift, Tool Design and Qualification, Casing and Connections, Design and Evaluation, Production and Operations, Surface Facilities, Subsea Systems, Gas Well Dewatering, Heavy Oil, Drilling and Completions, Multilateral Wells, Sand Control, Risk and Reliability, Quantitative Risk and Reliability Assessments, Risk-Based Maintenance Planning, Reliability-Based Design, Pipe-Soil Interaction Analysis, Defect Assessment	http://www.cfertech.com Larry Staples, President, Phone: 780 450 3300, Fax: 780 450 3700, Email: l.staples@cfertech.com
Inst Francais du Petrole (France)	CO2 Capture & Storage, Heavy Crudes & Tar Sands, Ultra-Deep Reservoirs, Petroleum System Evaluation, Basin Modeling, Improving Oil Recovery, IOR, Reservoir Characterization, Simulation & Monitoring, Uncertainties & Risks, Productivity & Injectivity of Wells, Ultra-Deep Offshore, Flow Assurance & Equipment, Gas Treatment	http://ExplorationProduction.ifp.fr Email: Exploration-Production@ifp.fr
International Research Institute of Stavanger (Norway)	Reservoir Characterization and Simulation, Stochastic Modeling, Upscaling, Pore Modeling, Advanced Well Modeling, Computational Fluid Dynamics, Well Testing, Basin Modeling, IOR, Carbonate Reservoirs, Water/Gas Management & Shut-off, CO2, Chemical and Microbial EOR, Improved Well Productivity, Formation Damage, Well Construction and Risk Management, Drilling Engineering, Wellbore Mechanics, Real Time Planning and Control Systems, Reservoir Description and Utilization, Well-Reservoir Interaction.	http://www.iris.no/internet/petroleum.nsf Aina Margrethe Berg, Sr. Vice President, Phone: +(47) 55 54 38 68, Fax: +(47) 55 54 38 60, Email: aina.Berg@iris.no
Rocky Mountain Oilfield Testing Center (USA)	Oil and gas production, enhanced oil recovery, EOR, oil and gas drilling, geothermal drilling, renewable energy, flow assurance, bio-remediation, beneficial use of produced water, well completions, geology, geophysics,	http://www.rmotc.doe.gov Connie Wallace, Business Development Manager Phone: 888-599-2200, Fax: 307-233-4851, Email:

	geochemistry, petrophysics, CO2 sequestration, reservoir management, reservoir characterization, coal bed methane, stripper production optimization, new drilling techniques, new downhole pumps and sensors.	connie.wallace@rmotc.doe.gov
SINTEF Petroleum Research (Norway)	Develop solutions for exploration, field development and production. Special fields are basin modelling, seismic, rock mechanics, drilling and well construction, wellstream and reservoir technology.	http://www.sintef.no/petroleum May Britt Myhr, President, Phone: +47 73 59 12 14 Fax: +47 73 59 11 02, Email: may.myhr@iku.sintef.no
Southwest Research Institute®	Multiphase flow, flow assurance, hydrates, drilling hydraulics, safety valve testing, sand screen erosion, drilling hydraulics, wet gas, flow measurement, corrosion analysis, materials, deep ocean simulation, fatigue testing, computational fluid dynamics, finite element analysis, probabilistic failure analysis, environmental testing, surface engineering and coatings, computational mechanics, structural mechanics, thermal analysis, life prediction, process engineering, fire testing and research.	http://www.swri.org
Western Australian Energy (Australia)	Integrated multi-disciplinary teams are being created across geology, geochemistry, petrology, hydrogeology, rock physics, geomechanics and reservoir engineering to bring about the required step-change developments in energy technology. Current research and development are those associated with the burgeoning hydrogen economy, gas-to-liquids processing, and gas to solids (hydrates).	http://www.waera.com.au Robert Johnson, Acting Chief Executive, Phone: +618 6436 8500, Fax: +618 9463 6005, Email: robert.johnson@waera.com.au

Other Industries and General Applications

The availability of uncertainty tools available in other industries and/or as general applications was also considered. This section presents a review of some of the available commercial software packages for conducting uncertainty analysis in different areas.

Crystal Ball

This is a Microsoft Excel-based program offered by Oracle. Crystal Ball is the leading spreadsheet-based application suited for predictive modeling, forecasting, simulation and optimization.

Oracle Crystal Ball solutions is composed of Oracle Crystal Ball, Oracle Crystal Ball Enterprise Performance Management, Oracle Crystal Ball Enterprise Performance Management and Oracle Business Intelligence (BI) applications. From these tools, Oracle Crystal Ball provides predictive modeling, Monte Carlo simulation, and forecasting.

Oracle Crystal Ball Decision Optimizer is an option for Oracle Crystal Ball that adds the advanced capabilities of optimization and calculation speed to Oracle Crystal Ball's powerful simulation and forecasting toolset. Crystal Ball uses a two-stage Monte Carlo simulation method presented by Cohen, et, al. (1996) to distinguish between variability and uncertainty in the new version.

Contact Info:
http://www.oracle.com/crystalball/index.htm

@RISK

This is a Microsoft Excel-based program that performs risk analysis using Monte Carlo simulation. Its objective is to show many possible scenarios to calculate how likely they are to occur. Because @RISK is a true add-in to Microsoft Excel, there are a significant number of functions that are coupled to Excel's function library.

@RISK offers up to 35 probability distribution functions. Distributions may be selected from a graphical gallery or can be defined using historical data for a given input. Distributions may be provided using percentiles as well as standard parameters. Fitted distributions are ranked based on three statistical tests, and may be compared graphically.

Input distributions may be correlated with one another, individually or in a time series. All @RISK functions and correlations in the model are summarized—with thumbnail graphs—in the dashboard-style @RISK Model window. Distribution graph pop-ups can be watched when browsing through the spreadsheet cells.

The result of a simulation is a look at a whole range of possible outcomes, including the probabilities that they will occur. Graphing the results is possible with histograms, scatter plots, cumulative curves, Box Plots, and more. The user can identify critical factors with Tornado charts and sensitivity analysis. The results can be pasted into Excel, Word, or PowerPoint, or placed in the @RISK Library for other @RISK users. The results and charts can be saved within the Excel workbook.

Contact Info:
http://www.palisade.com/risk/?gclid=CKbthKXAjJsCFRIeDQodT0eOpg

Analytica

This is a stand-alone program for creating, analyzing and communicating probabilistic models for risk and policy analysis. It is a visual software package developed by Lumina Decision Systems Inc., for creating, analyzing, and communicating quantitative decision models. Analytica includes hierarchical influence diagrams for visual creation and view of models, intelligent arrays for management of multidimensional data, Monte Carlo simulation for analyzing risk and uncertainty, and a general modeling language. It is designed to enable the creation of models that are transparent, interpretable, extensible, and flexible. The design of Analytica is based on key ideas from the field of decision analysis.

Analytica is widely used for policy analysis, business modeling and risk analysis, with applications in areas such as energy, health, pharmaceuticals, environmental risk, wildlife management, defense, R&D planning, financial services, aerospace, and manufacturing.

Contact Info:

http://www.lumina.com/ana/whatisanalytica.htm

RiskQ

This is a general tool for the analysis of probability and distributions. It can be utilized to carry out task such as: experimental data analysis, ANOVA (Analyisis of Variance), MANOVA (Multivariate Analysis of Variance), ANCOVA (Analysis of Covariance), general linear-regression analysis, adjust p-values from multiple tests, apply common parametric and nonparametric statistical tests, compare correlation matrices, characterize distributions reflecting uncertainty or inter-individual variability of system inputs and/or output(s), perform parametric and nonparametric sensitivity analysis and automatically characterize the Monte-Carlo estimation error of any simulated output.

This software, implemented in Mathematica, uses theoretical distributions to represent inputs or input distributions, based on empirical data or combinations of theoretical and empirical inputs. Probability distributions can be built and manipulated reflecting those inputs. Distribution(s) representing uncertainty/variability can be generated in any arbitrary output function of random input, each represented by a corresponding input distribution that is specified or designed.

RiskQ functions facilitate the characterization of uncertainty and discrete probability calculus. RiskQ also contains a variety of parametric and nonparametric statistical functions. Simulations can be carried out using Monte-Carlo, Latin-Hypercube, or Systematic Latin-Hypercube approaches, to generating pseudorandom variates with any feasible, user-specified rank-correlation matrix. Graphical functions specifically designed to assist quantitative uncertainty analysis are also being developed. RiskQ's "Data" function (unlike common "spreadsheet" applications) makes it easy to manipulate tabular data, using efficient, symbolic commands to sort data, merge data sets, merge dataset columns or rows, transform or add new data, and bin or classify data (i.e., combine data rows having unique values of one or more specified column variates, using user-specified rules to combine column data).

Contact Info:

http://www.exetersoftware.com/cat/loehle/riskq.html

Lumenaut

This is an Excel software add-in featuring a Monte Carlo Risk Simulation package, a decision tree analysis package and a parameter and non-parametric statistical package.

Contact Info:
http://www.lumenaut.com/

UncertaintyAnalyzer 3.0

Uncertainty analysis software, from Integrated Sciences Group, is a windows-based application that quantifies the uncertainty of experimental measurements. It is a tool for conducting and reporting uncertainty analyses for direct measurements, multivariate measurements and measurement systems. It incorporates and extends the concepts and methods found in the ISO Guide for the Expression of Uncertainty in Measurement (the ISO GUM). Consequently, it facilitates compliance with ISO 17025 and ANSI/NCSL Z540.3, which are utilized in procedures in analytical chemistry. Built-in statistical analysis methodologies are combined with user technical expertise through a user-friendly graphical interface.

Contact Info:
http://www.isgmax.com/ua_product.htm