Paper 2.2

Developing Measurement Infrastructure in BP Azerbaijan

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1 INTRODUCTION

This paper covers the development of a sustainable Measurement Operation in BP Azerbaijan Strategic Performance Unit (AzSPU).

The Early Oil Project (EOP) metering consisted of 7 BP operated Fiscal, or Class 1 [1], metering stations in 2004, burgeoning to 16 operated and 3 non-operated Fiscal metering stations in 2009 through the Azeri-Chirag-Guneshli (ACG) Field Development Project Phases. In addition to the Fiscal meters, there are around 120 Allocation, or Class 2, [1] meters either as standalone instruments or as 'virtual' meters.

The challenge has been to address the scope growth through the introduction of an SPU Measurement Strategy.

The strategy describes an SPU Management of Measurement structure based on an ISO10012 [2] model. The model identifies interfaces between 10 direct measurement personnel and subcontract meter operators, measurement service providers, Hydrocarbon Accountants, Customs Inspectors and itinerant auditors.

Other key objectives of the strategy are:

- Meeting the 'localisation' agenda - National Engineer and Technician competency development;
- Development of Regional calibration services;
- Sustainable resourcing policy
- BP Operating Management System (OMS) compliance for Measurement
- Develop meaningful, cross-Asset key performance indicators (kpis) for all Fiscal and Allocation class measurements

To supplement the Strategy, a lower level SPU Measurement Operations Management Procedure has been adopted to 'standardise' on practices across three Export pipelines and two marine terminals spread across three countries.

The next objective of the Strategy is to 'land' the calibration and management of Allocation level meters under the existing framework leading to kpis and demonstrable OMS compliance.

2 MEASUREMENT INFRASTRUCTURE IN BP AZERBAIJAN TODAY

BP Azerbaijan is involved with Exploration and Production Operations under Production Sharing Agreements (PSA):

- The ACG PSA, signed in September 1994, covers the 30 year development of the Azeri-Chirag-Guneshli contract area. During 2009 around 310 million barrels of crude oil and 32 billion cubic feet of gas were exported from the contract area.

- The SD Production Sharing Agreement (PSA), signed in June 1996, covers 30 year development of the Shah Deniz contract area. During 2009 around 15 million barrels of condensate and 185 billion cubic feet of gas were exported from the contract area.

2.1 Azeri-Chirag-Guneshli (ACG) Field Development

The field has been developed in several Project phases, initially as the EOP, and then as ACG Field Development Project Phases running in tandem with Sangachal Terminal Expansion Project, STEP.

The ACG Field Development encompasses:

- Chirag offshore facility, which has been producing since 1997 as part of Early Oil Project EOP.
- Central Azeri offshore complex - CA PDQ and CA CWP facilities which came on stream in 2005 was known as ACG Project Phase 1
- West Azeri (WA) and East Azeri (EA) facilities which came on stream 2006 and 2007 respectively as ACG Project Phase 2 delivery.
- ACG Project Phase 3 delivery - Deepwater Guneshli (DWG) offshore facility complex, DWG DUQ and DWG PCWU, which began production in 2008.
- ACG Project Phase 4 or the Chirag Oil Project, (COP), will deliver a further offshore facility, West Chirag.

2.2 Sangachal Terminal Expansion Project - STEP

Sangachal Terminal was built as part of the EOP to receive and process Chirag, or ACG Partner, crude exporting crude oil to Novorossiysk or Supsa Terminal in Georgia.

Expansion of the terminal came through STEP phases to accommodate increased production from the Azeri and DWG fields, adding additional stabilisation trains, a gas processing plant and three new stabilised crude oil export routes.

- EOP facilities were designed to process around 100,000 bbld from the Chirag platform and comprised crude stabilisation facilities (flash gas separators and fired heater trains), stabilised crude storage tanks and export pumps supporting two Export routes - Western Route Export Pipeline (WREP) and Northern Route Export Pipeline (NREP).
- STEP Phase 1 – added Azeri Field pipeline reception facilities, additional heater trains, additional storage tanks and EOP interface, completed 2005. Notional processing capacity 600,000 bbld.
- STEP Phase 2 – added additional processing trains and heaters, completed 2006, Notional processing capacity 1,000,000 bbld.
- STEP Phase 3 – Shah Deniz gas plant, completed 2006.
- Combined STEP has: two Import Class 1, or ‘Fiscal’, crude oil meters; three Export Class 1 crude oil meters; three Sales Gas Meters and one Export Class 1 Condensate meter

2.3 Shah Deniz (SD) Field Development

Initial development of Shah Deniz field saw the installation of an offshore facility, subsea pipeline and gas processing plant.

- Shah Deniz Stage 1 – Shah Deniz Alpha (SDA) TPG Platform, subsea pipeline, gas processing plant, two Sales Gas Export routes and one condensate Export route
- Shah Deniz Stage 2 – subject to final investment decision, is likely to entail around 30 subsea wells, 2 further platforms, gas plant expansion and additional Class 1 meters currently under development as Shah Deniz 2 Project by the Shah Deniz Full Field Development Project organisation.

2.4 Baku-Tblisi-Ceyhan (BTC) Pipeline

The pipeline is owned by BTC Company and operated, on behalf of the BTC shareholders, by BP. The Turkish section of the pipeline and tanker loading terminal are operated, on behalf of BTC, by BOTAS International Ltd. (BIL).

- 1,768 km pipeline, with 4 pump stations
- 1 operated Class 1 crude oil meter and 2 non-operated Class 1 crude oil meters.
- 80 block valve stations,
- Ceyhan Marine Terminal with two Class 1 crude oil meters

2.5 Southern Caucus Pipeline (SCP)

The pipeline is owned by SCP Company and the Technical Operators whilst Statoil are the Commercial Operators.

- 690 km pipeline with 2 compressor stations
- 2 pipeline Class 1 gas meters
- One Sales Gas Class1 meter take off in Georgia
- One 'check' Custody Transfer meter in Georgia
- Subject to final investment decision the SCP Expansion Project will significantly increase gas processing capacity and bring additional gas metering.

As described, the field development and Regional infrastructure indicates multiple PSA and Operations organisations. These represented, diagrammatically, in Figure 1 below.

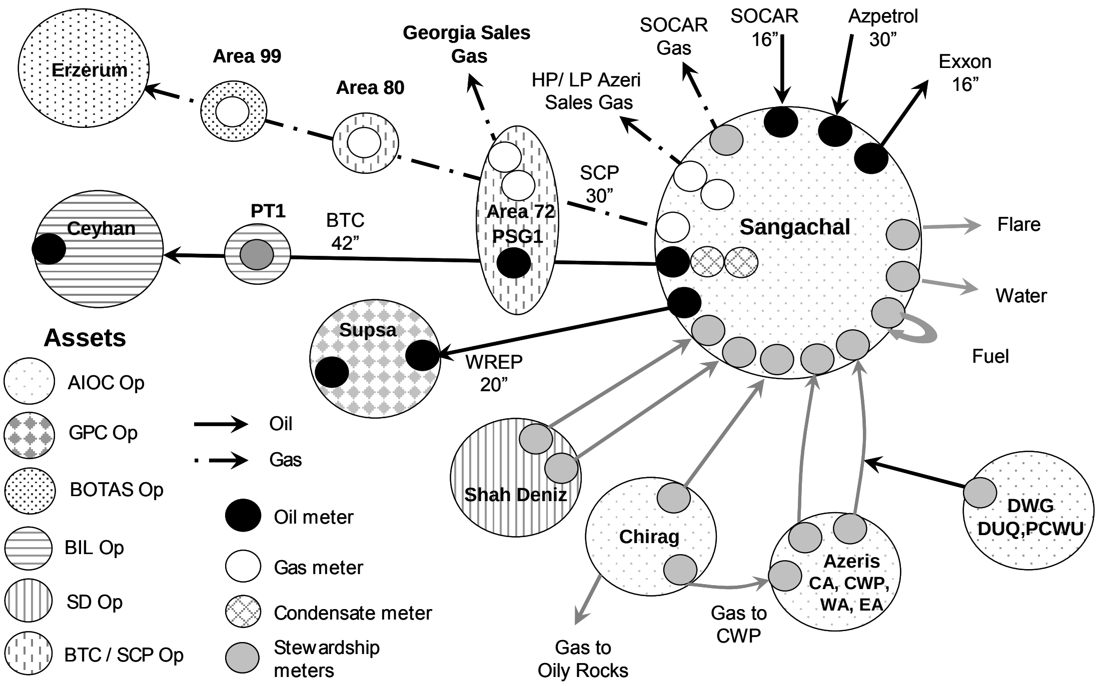

Figure 1 - AzSPU 2010 Measurement Infrastructure

3 SPU MANAGEMENT OF MEASUREMENT STRATEGY

Several interfaces can be identified in the AzSPU Measurement infrastructure that, in the main, can be grouped as follows:

- Geographic - pipelines crossing three countries
- Organisational - operated and non-operated meters
- Regulatory - Azerbaijan, Georgian and Turkish Government Revenue Agencies
- Commercial - different shareholder groups

3.1 Measurement Strategy Objectives

Through cross SPU consultation and in line with ETP 64 requirements, an SPU Metering strategy [3] was drafted. This document indentified a number of objectives as being key to measurement discipline 'health'. The high level objectives are identified below:

- Metering 'functional' management achieved through workgroup representation.
- Establish key performance indicators for Metering Function
- Sustainable develop of Local Resource and Service Provision.
- Competency Development
- Equipment Rationalisation

The ensuing sections of this paper take a closer look at each of these objectives, describes how they were achieved using a mix of existing, Regional capability with out of Region development support and offers critical comment on the level of success realised.

3.2 SPU Management of Measurement Model

BP Engineering Technical Practice (ETP) approach to a Management of Measurement Model is defined, in [1], as:

- compliance with ISO 10012:2003 [2] for BP operated meters
- for non-operated meters, the BP SPU with exposure to liability for measurement shall influence and monitor the Operator for compliance with ISO 10012:2003, as far as is reasonably possible.

Reference [2] covers the lifecycle of a Measurement Operation from Commercial negotiations, through Contractual agreements and Regulatory interfaces to Internal Accounting and Operations. BP Commercial requirements for Measurement are also described in Hydrocarbon Value Realisation draft practice, [4].

The Management of Measurement process and continuous improvement cycle is shown in Figure 2.

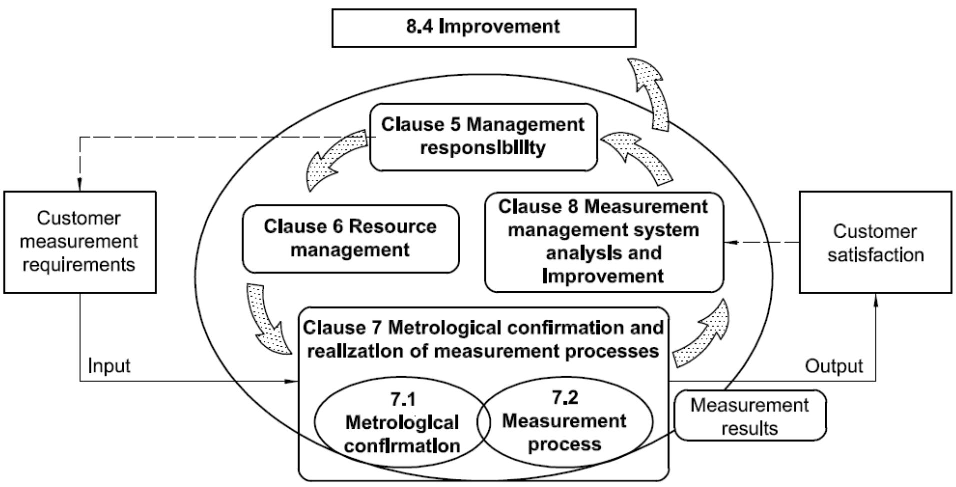

Figure 2 - Measurement Management System Model [1]

Given the model, it was possible to identify and fit existing SPU roles to each of the clauses shown in the Figure 2.

[1] Figure 2 adapted from reference [2]

In terms of the SPU structure, the SPU Engineering Authority (EA) [5] is accountable for implementing BP procedures and practices so has management responsibility for the Management of Measurement Process, relating to Clause 5 of the model.

Clause 6, the resources and equipment associated with execution the measurement processes are attached to individual SPU Assets i.e. Measurement Discipline Responsible Engineers (DRE), Metering Technicians and Metering Test Equipment are under the management of the Asset Maintenance and Asset Engineering Organisations

Approved procedures, designed to preserve meter design uncertainties, are used for the Metrological Confirmation, Clause 7. The 'Custodian' of the procedures is the Asset DRE, whilst the Measurement Process is implemented through 'Maximo' [6] maintenance scheduling package, supplemented by 'Metrology' [7], a proprietary specialist Metering Maintenance software tool.

To address the requirements of Clause 8, monitoring and improvement of the Measurement cycle is delegated to the SPU Measurement Technical Authority (MTA) by the SPU EA. Monitoring is achieved through a combination of mechanisms:

- Measurement 'health' reviews e.g. metering personnel competencies assessments & training recommendations, equipment reliability and obsolescence assessments
- site inspections
- MTA participation in Partner audits
- MTA review of Class 1 and Class 2 meter Management of Change (MOC) activities
- MTA approval of Measurement related procedures
- Regular SPU and E&P Segment Measurement Community of Practice meetings

Performance is reported in Annual Measurement Reviews and recommendation raised to address any issues identified.

The SPU Measurement function can be represented as in Figure 3 below.

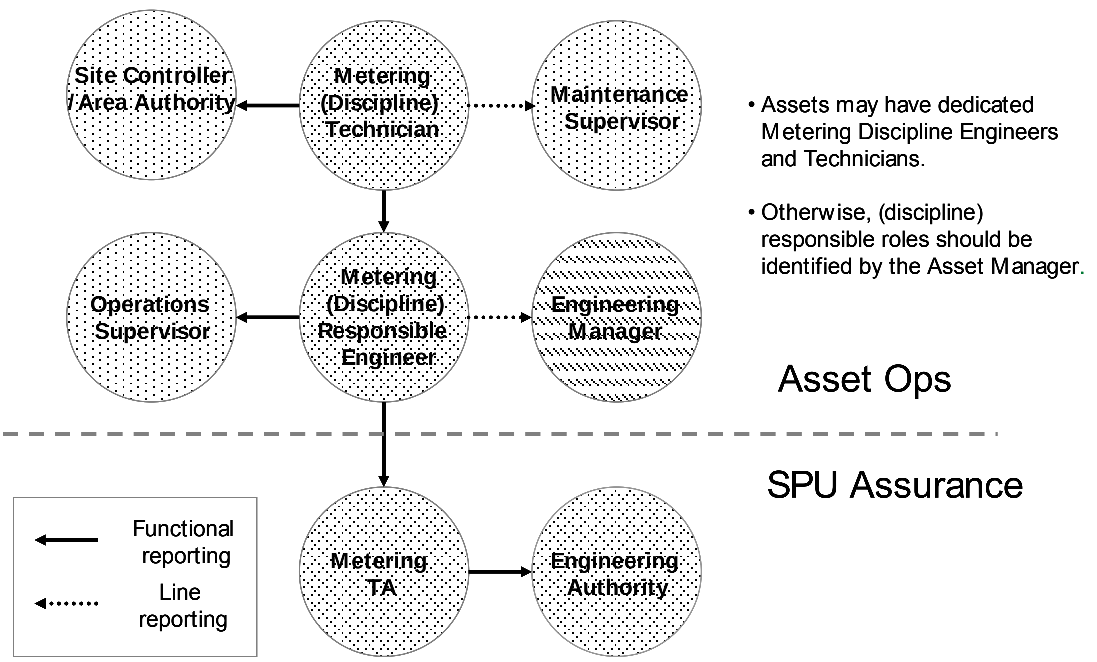

Figure 3 - SPU Measurement Function Structure

3.3 Measurement Function Customer Requirements and Expectations

Also identified in the model are Customer Measurement Requirements and Customer Satisfaction elements which bring a wider lens to the SPU Measurement Function.

The Customer Measurement requirements are identified early in the field development cycle to meet Contractual and Regulatory development obligations. These obligations are translated into Operational systems through the collaboration of the Commercial HVR organisation, SPU Operations organisation, Project Organisations and System Manufacturers. In BP the link between the Projects organisation and the Operations organisation is through the Discipline TAs, in the case of Measurement, through the MTAs. The Project Organisation may not have an explicit, full time MTA in which case the function is embedded in a suitable role e.g. Control Systems or Instrument TA.

Customers of the Measurement cycle are manifold but are managed through the Commercial HVR organisation in accordance with local Regulatory requirements and Commercial Agreement. The Development and Operations phase of a meter can be represented diagrammatically, as in Figure 4 below, below with SPU Measurement model identified accordingly.

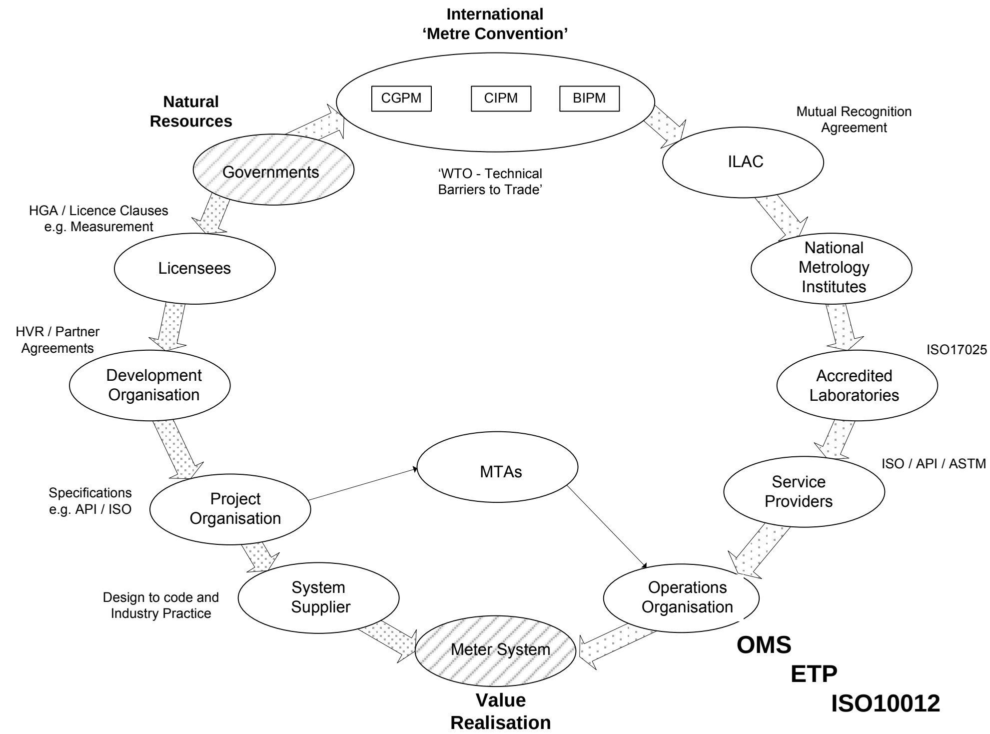

Figure 4 - Meter Development - Operations Phases

4.0 MEASUREMENT FUNCTIONAL MANAGEMENT

Metering Strategy measurement 'functional' management is described in terms of workgroup representation.

The workgroups are not formally defined in terms of 'committees' but are composed of personnel who, through their day to day activities influence, or can be influenced by measurement activities.

Depending on the area of the 'function' requiring attention, different representation from the SPU may be required. This can include Asset Operations and Maintenance (O&M) personnel, Procurement & Supply Chain Management (PSCM) representatives, Service Providers, Commercial Analysts and Partner Representatives. To assure consistency and continuity of measurement practice it is also usual to involve the MTA.

Examples of objectives achieved, some of which are described in greater detail in the following sections, include:

1. Development of Regional vendor prover calibration service delivery to Internationally accepted performance delivery: various people, at various times over a two year period, input to this process including SPU Senior Management and representatives from BP PSCM, BP Engineering, AzSPU O&M, Fabricators, Regional Service Provider, Accreditation Agencies and MTA.

2. Development of metering 'manning' strategy: assessing the requirement of existing and increasing workload and the logistics of manning remote meter stations. This was discussed between Project, O&M personnel and MTA, resulting in a resourcing model.

3. Development of competency standards for Metering Technicians using BP common business processes: in terms of the Measurement function, an existing model was enhanced to monitor training progress and a proposal made for funding which resulted in successful contract placement. The work group involved with this process included Asset Maintenance Management, Discipline Coaches, PSCM and MTA.

4. Development of an 'in Region' generic calibration capability with robust traceability: calibration costs for general plant test equipment from across all of the SPU Assets were high and subject to long turnaround. A strategy and plan to develop an 'in Region' calibration facility through partnership of a UK calibration service provider and local partner was worked by SPU Discipline Engineers, Asset O&M personnel, PSCM, Service Providers and TAs.

5. Development of a Measurement Operations Management Procedure [8]: the document reflects a cross SPU common approach to the high level guidance or the minutiae not captured in [6] and it will form the basis of a Site Technical Practice. The document was developed by a work group of Measurement DREs, Measurement Technicians and MTA.

6. Coordination of close out of third party Measurement Audits by cooperation between HVR, Asset O&M, Measurement DREs and MTA.

Whilst this approach may seem entirely reasonable it should be noted that there have been as many as a dozen or so discipline engineers involved in item 2. and 3. above, as well as O&M and Project Operations staff. Management of the number of personnel involved, diversity of representation and on occasion Commercial sensitivity, has been greatly simplified through the adapted ISO10012 model.

5.0 KEY PERFORMANCE INDICATORS

The Metering Strategy [3] identifies high level performance expectation statements for Class 1 meters.

These are that Class 1 oil Export meters are Operated such that the measurement uncertainty will be managed within ± 0.25% dry mass and that Class 1 gas Export meters will be operated within ± 1% uncertainty tolerance. This is generally accepted industry practice today.

These tolerances are derived from uncertainty calculations which assess component and then system uncertainty based on assumptions around instrument repeatability and stability.

To manage the system uncertainty, sets of calibration and maintenance processes have been created for all Class 1 oil and gas meters - there are around 12 sets in place. The activities associated with these procedures are scheduled in Maximo [6] but output from the procedures is stored in Metrology [7].

Maximo is the BP Common business tool but is used primarily as a scheduler for Class 1 meter calibration. The reason for this is that Maximo does not have the capability to calculate complex 'expected' values required for the calibration procedures e.g. Maximo does not have the capability to calculate local gravity and deadweight tester temperature compensations nor can it calculate API VCF for densitometer referral. Metrology does have this capability and provides an electronic record of Operations and Calibration activities along with 'uploaded' calibration certificates for some Field Equipment and Test Equipment.

Proposed key performance indicators for Measurement performance were therefore based around Maximo as follows:

- Maintenance related kpi:

'99.9% of Planned Maintenance will be complete to within 1 period of review date. At the review date 100% of Corrective Maintenance, will be complete or planned to completion'
i.e. at the time of the review, 99.9 % of the review period PMs will be completed. Where Corrective Maintenance has been required this will be completed or commitment given to a completion date with supporting plan.

% PM completion	Performance rating %
>99.9	100
>99	50
<99	30

Table 1 - Maintenance related kpi

- Operations related kpi

'No Corrective Maintenance is required as an outcome of Audit / Inspection findings'
i.e. during the review period all corrective maintenance has been identified and completed or planned to completion. This is designed to ensure that where equipment or procedure failure is identified, this is communicated onward for resolution

No. CM [2] actions raised through audit	Performance rating %
0	100
1	50
>1	30

Table 2 - Operations related kpi

- Commercial Compliance related kpi

'No non-compliances with PSA, Commercial Agreements or Industry Good Practice, identified as an outcome of Audit / Inspection findings'
i.e. during the review period, no non-compliances with 3rd Party obligations are identified as an outcome of Audit / Inspection findings

[2] Corrective maintenance

No. of non-compliances raised through audit	Performance rating %
0	100
1	50
>3	30

Table 3 - Commercial Compliance kpi

The proposed kpis have not been formally agreed but current metrics, based on audit performance, currently run at around the 50 % performance rating level for Exports measurement.

6.0 DEVELOPING LOCAL RESOURCE COMPETENCY

Industrial oil production in Azerbaijan started the 19th Century with hand dug wells. Development of the Oil industry continued through the period 1885 -1920. By the beginning of the 20th century, Azerbaijan was producing more than half of the world's supply of oil. In 1941 Azerbaijan extracted 23.5 million tonnes of oil - around 70% of the former Soviet Union oil production. In November 1949, the first Azerbaijan offshore oil well was drilled in “Oily Rocks”.

After the signing of the “Contact of the Century” in 1994, foreign investment in the oil industry rapidly increased with the construction of modern Offshore platforms, oil and gas pipelines through the EOP, ACG, STEP and Shah Deniz Projects.

The rapid expansion from a few to several oil meter systems clearly required additional skills and placed increased demand for O&M Engineering and Technician resources.

6.1 Initial Local Technician Resourcing / Competency Development Strategy

In recognising the requirements of localisation, under the ‘Contract of The Century’, the strategy [3] identified the need for managed localisation of measurement personnel. A Regional service provider had provided metering technicians for some calibration work on EOP meter systems but they were not fully competent in some areas required by the calibration & maintenance procedures in support of the STEP / ACG Project Class1 meter kpis.

The BP personnel who had been involved with EOP meter systems were split, along with one set of test equipment, between the emerging Exports and Sangachal Performance Units exacerbating the issue of metering cover.

A Workgroup, section 4, item 2, discussed and identified two key resourcing issues:

- BP ‘in Region’ capability was not fully competent and was extremely limited by available numbers
- ‘in Region’ vendor capability was not fully competent and would require training to bridge between GOST and API / ISO practices to support STEP / ACG Project Class 1 meter systems

The resourcing model used for the early stage of Phase 1 Project development was to use Expatriate discipline coaches, supplemented by local technicians and trainee technicians recruited into BP. After 3 months basis discipline training, at the Caspian Technology Training Centre (CTTC) based near Sangachal Terminal, and successful ‘passing out’ the technicians would assist the coaches on live plant in O&M activities. Following a period of training on plant the trainees could then be competency assessed against discipline criteria in [9] and become fully competent discipline technicians.

It was clear to the Workgroup, that metering discipline coaches would be required. Since the number of systems would ramp up over 18 months, or so, it was concluded that coaches could do meter system O&M related work part time and coach metering technician trainees part time. A business case was developed and successful application made to the various Partner Group Contract Committees for funding based on a manning strategy of 'back to back' Expatriate Metering coaches - 4 based in Sangachal Terminal, 2 at Pump Station 1, on the BTC Pipeline in Georgia (PSG1), and 2 based at Area 80, on the Southern Caucuses Pipeline (SCP) in Georgia. In 2005 a 2 year contract was awarded to a European Service provider for the supply of Metering Coaches who would train and assess technicians to NVQ level competency. Trainee Instrument Technicians, from the CTTC training pool, who demonstrated an aptitude for metering or a bias towards the technological end of the instrument discipline spectrum would be assigned to the coaches for metering competency development.

After some time it became clear that localisation progress would be at the lower end of expectations. This was attributed to a number of factors, most significantly:

- The workload on the coaches - as well as routine O&M work, some considerable time was spent supporting Commissioning activities as new systems came into Sangachal i.e. the Sangachal coaches workload was underestimated
- Trainee technician availability - priority was given to filling Instrument Technician vacancies to support plant Operations, although one Trainee Technician per shift had been assigned some way into the program

In considering how to move forward from this position it should be noted that concern was expressed that competency standards should be biased toward European type competency standards as opposed to the local GOST competency standards. On investigation it was found that the GOST competency requirement was more around licensing and registration of Engineers and Technicians than supporting competency development. No hard and fast 'curriculum' could be found.

Further concerns were expressed that local vendor technicians were no longer called upon for calibration work they had previously carried out so the initial strategy, in fact, appeared to reduce local content of work.

A one year contract extension, through 2008, was approved as a buffer to consider ways to localisation and still provide metering O&M cover in the interim period.

6.2 Rationalising Technician Resource Loading

In light of Regional operating experience, a more 'formulaic' approach could be taken to establishing work loads in the context of local competency development.

At each of the three locations, where metering technicians were based, a load index was calculated based on the number of meter streams each technician would maintain. (For the purposes of the index each sampler loop, analyser loop and prover was also taken to be a single meter stream). At each location we also asked the question - "How does your workload feel" and the answer could be anyone of three from 1. "too high"; 2. "about right" or 3. "have time to get involved in other plant systems". The results of the survey are shown in Table 4:

	O&M Resource (expat + local + trainee)		**Class 1 meter stream per fcr[3]**	**“feels like” / “should feel like”**
a) Asset based resource, continuous operation	Sangachal PSG1 Area 80 Supsa	4 + 0 + 4 2 + 1 + 0 2	49 / 4 ≈ 12 18 / 2 ≈ 9 4 / 2 ≈ 2 9 / 0	Over loaded Slightly under loaded Under loaded ?
b) Country based resource, campaign operation	Azerbaijan Georgia	4 + 0 + 4 4 + 0 + 1	49 / 4 ≈ 12 31 / 4 ≈ 8	Over loaded Slightly under loaded
c) SPU central resource, campaign operation	SPU	8 + 0 + 5	80 / 8 ≈ 10	About right

Table 4 - Meter Technician loading

From Table 4, optimal resource loading would appear to be more likely with a central resource, based in Sangachal, servicing the whole SPU, option c, than the existing option a. The drawbacks to that however, were that it would not readily support development of Georgian local technicians, nor would it support first line intervention in the case of equipment failure. (It could take two days to mobilise a technician to PSG1 from Sangachal, subject to commercial flight availability).

Of the remaining options, country based resourcing was closest to optimal however; according to previous experience the technicians at Sangachal would still be ‘overloaded’. In considering resourcing options it was acknowledged that there were ‘near competent resources’ (ncr), or technicians, available from a Regional service provider. It was believed that certain activities could be carried out by the ncr with minimal supervision which would reduce the loading on the Sangachal fcr. In fact, to engage two ncr would reduce the loading index to somewhere around 8 for Sangachal. In principle, this reduction should also free up more time for coaching. For the manning situation in Georgia it was also noted that the trainee there was in fact near competent so the final strategy identified loadings as 49 / 6 ≈ 8 for Sangachal (Azerbaijan) and 31 / 3 ≈ 10 for Georgia, noting that this now included the Supsa meters.

The forward resourcing strategy, from 2008, would be to have 4 fcr and 2 ncr based in Sangachal Terminal and to have 2 fcr and 1 ncr based at PSG1 in Georgia. The decision to engage, full time, ncr from the Regional Service Provider satisfied the concern that local resources work load had dropped. An outline shift pattern could be developed, show for Azerbaijan, in Figure 5:

[3] Fully competent resource

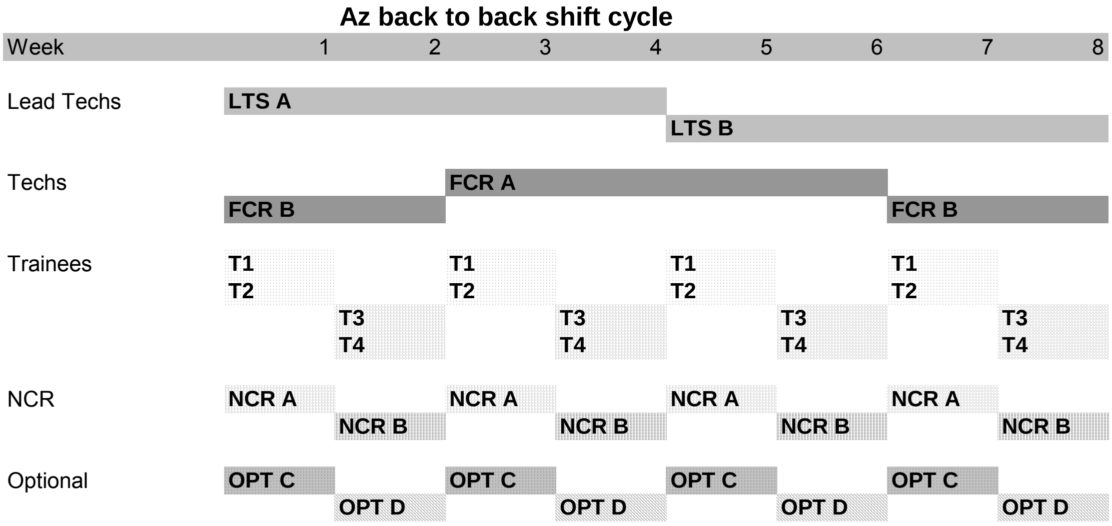

Figure 5 - Outline Shift Pattern

The Azerbaijan shift pattern indicates resourcing for any one shift:

- one Lead Technician (also and fcr)
- one fcr
- one ncr
- two trainee
- one optional training slot (this was never taken up due to fcr work load but was used for intermittent training for Engineer training)

similarly, the Georgian shift pattern resourcing:

- one fcr
- one ncr
- one trainee

With manning levels now established, the next consideration was how to implement local technician competency development in an effective manner, and to set and commit to localisation targets. It was felt that competency development, within a BP framework i.e. CMAS [9], would be most likely to be effective with direct control over competency standards, assessments and give better insight into competency development progress. The choice of BP CMAS obfuscated the discussion around competency standards and the use of CMAS, in relation to metering competency, is described in the next section.

6.3 Local Technician Resource Competency Development and CMAS

CMAS is BP's Competency Management Assurance System. It defines technician competency, and records assessed competency level, i.e. competent or not competent, in terms of 5 generic standards:

1. Implementation of Maintenance Procedures and Adjustment:
   management of a maintenance task involving e.g. requirements for permit to work, isolation certification, P&IDs, loop drawings, recording adjustments, Maximo sign off.
2. Interrogation and Fault Finding Skills:
   clarifying and diagnosing the cause and extent of faults in equipment and systems
3. Inspect and Repair Systems for Restoration to Required Performance:
   repairing system components and equipment, evaluate the feasibility of the repair.
4. Return Equipment to Service by Component removal and replacement:
   remove and replace system components and equipment
5. Monitor and Assess Performance and Condition of Equipment:
   monitor and assess performance and condition of equipment using different methods, e.g. control charts, visual inspection, documented information, measurement spot checks.

These 5 standards are applied to Units. Units are, effectively, subsets of Disciplines. The Metering Technician Discipline has the following Units:

- Supervisory, Control and Data Acquisition System interface
- Temperature Measurement
- Pressure Measurement
- Flow Measurement
- Proving Operations and Maintenance
- Analytical
- Density Measurement
- Valves

Each Unit has Elements - for the 8 Metering Units there are 26 Elements and each Element has a Training Plan which will contain a number of critical tasks. The Elements are dependent on the installed equipment and therefore are, to some extent, site specific. For example, the AzSPU Density Measurement Training Plan has only one element (Density Measurement) consisting of 4 critical tasks, with applicable CMAS standards noted:

- Routine replacement of densitometers and update of densitometer constants in flow computers (Standards 1 and 4)
- Good practice in Log Book records of densitometer rotation / replacement and constants update. (Standard 5)
- Clean a contaminated densitometer and perform air check (Standard 1, 2 and 5)
- Procedure for returning a densitometer to manufacturer for repair / calibration (Standard 4)

In practice Standard 3 is rarely used as faulty or failed equipment is replaced (where spare are available), not repaired.

Occasionally, through Standard 5, it may be necessary to initiate Corrective maintenance e.g. excessive discrepancy between on line densitometers or between on line density measurement and Laboratory Measured Density.

The competency cycle of each critical task is 'SEE - DO - ASSESS', whereby a trainee will: watch a critical task being done, asking questions and will then participate in doing that critical task. When both trainee and coach are satisfied with experience and learning for all of the critical tasks in an element, the trainee is ready to undergo Competence assessment by the coach. In part, the decision to ASSESS is guided by the self assessment questions contained in each of the training plans. It may take several SEE-DO repeats before ASSESS is undertaken. The standard of assessment is reviewed by a Discipline Assessor to ensure consistency in competency assessments between trainees and the Assessor may recommend further training or Approve competence achievement in an element. The record of competence is kept in the iCANN database.

SEE-DO is a key metric for the coaches - it is effectively the training process - too many SEE-DOs for one task is indicative that the training has omissions or that, perhaps, the trainee does not have the aptitude for the task. To prevent possible turnover of trainees it was decided that only technicians who had completed the core elements from the Instrument Technician competency profile, would be assigned as Metering Trainee Technicians. If the aptitude or vocation for metering competency was not evident the Metering Trainee could return to the general Instrument Technician pool. In this way attrition of a scarce resource i.e. the local technician resource, would be avoided. The SEE - DO - ASSESS cycle is shown in Figure 6.

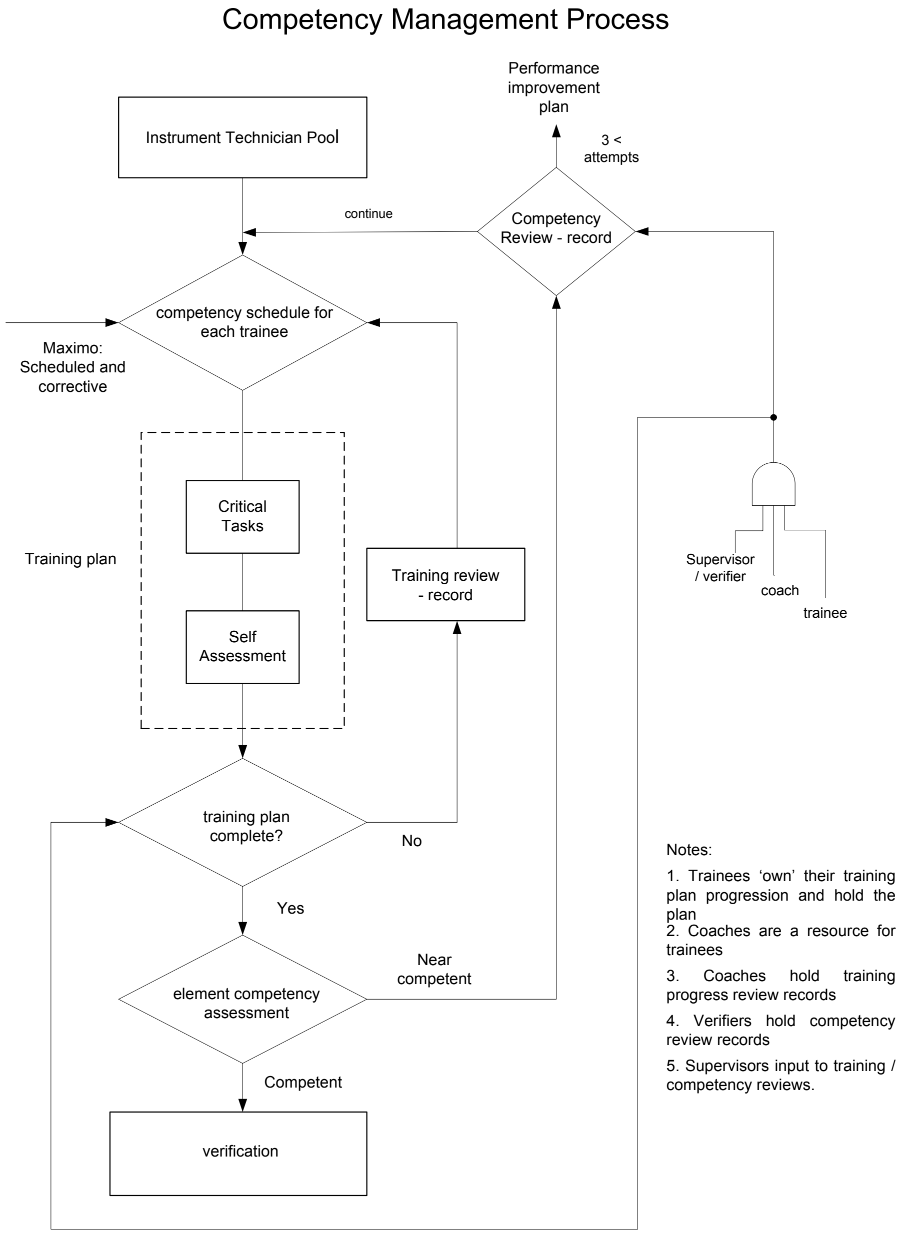

Figure 6 - SEE-DO-ASSESS Competency Development Cycle

Using Density Measurement Element as an example, the competency development of the local Metering Technician was structured in the following way. SEE - DO - ASSESS could only be undertaken when the relevant job plans were called up through Maximo, according to the Calibration & Maintenance schedule for Meter Systems. So for densitometer rotation / air checks the possible opportunities were mapped out in Figure 7.

According to his schedule there would be 12 possibilities to SEE - DO - ASSESS the four critical tasks in the Densitometer Training plan.

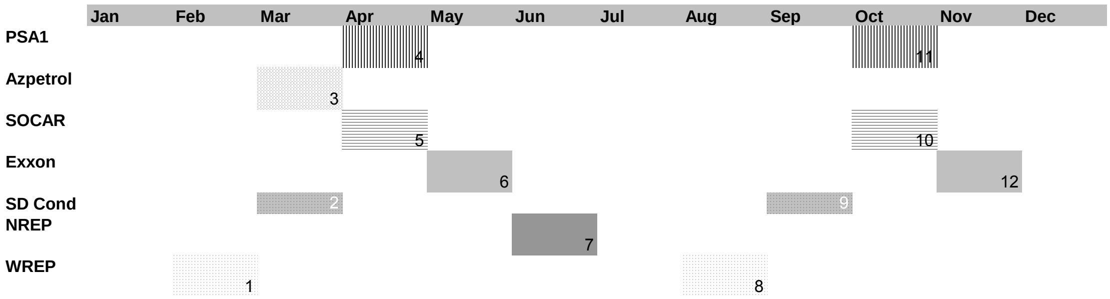

Figure 7 - Densitometer Job Plan Occurrence

So a Trainee may SEE on 2, DO on 7 and ASSESS on 12 and may supplement experience of the Training Plan through the intermediate occurrences.

To optimise SEE - DO - ASSESS opportunities it was decided to 'rationalise' Maximo and create a training schedule to include all Metering elements for up to eight trainees i.e.: Technicians 1, 2, 3 and 4; near competent resources A and B and Optional Training slots C and D. The rather complex task of fitting Maximo job plans to CMAS training plans to individual Trainees, to optimise training opportunities constrained by meter calibration & maintenance schedule requirements, was done by the Maximo planners.

On the basis of this resourcing strategy, a budget estimate was prepared and a business case presented to Partner groups for Approval. Budget was approved and 2 contracts were placed - 1 contract with a European Service Provider for the supply of 6 Metering Technician / Coaches and 1 contract with a Regional Service Provider for the supply of 2 'near competent' technicians.

At the time of writing the contract duration was around 80% complete and metering competencies in Azerbaijan are around 65% complete. The remaining competence elements are largely around metering ancillary equipment such as valve positioners. It is anticipated that localisation targets of having four competent BP local metering technicians, at contract end, will be met. The Regional Service Provider resource has been subject to some turnover and it is expected that 1 of the 2 ncr will be fully competent by contract end. Having the additional resource available in the market place, trained and competent to CMAS standards, will provide some flexibility in managing resourcing strategies going forward. The systematic approach described here can be readily repeated by local technicians and from that perspective; the Metering resource can be sustained using local resources.

In other areas of the SPU the progress is not quite so encouraging and it is reflects the underlying difficulties encountered in 'working' the interfaces within the SPU and so indicates where the Workgroup approach and communication of the Metering Strategy hasn't been quite so successful. Whilst training of local technicians has been ongoing there have been some delays to change out of coaches and availability of trainee technicians. The training which has been done has not been converted into completed Assessments and so there is little demonstrable record of competency attainment. At the time of writing this backlog was being worked as a priority and it is expected that a similar level of competency attainment, to that achieved in Azerbaijan, will be evident on completion of the Assessment backlog.

6.4 Developing Engineering Competencies

Along with increased demand for Metering Technicians and Engineers, the addition of gas orifice plate meters and analyser systems necessitated a more systematic, formal structuring of training and competency tracking. As already described, for technicians this was achieved using BP Competency Management Assurance System (CMAS) [9].

For Engineers this involves, on the job training, course attendance and assessment using BP Competency on Line (CoL). The competency set for Measurement Engineering in BP Exploration & Production Segment is still evolving; however, in 2008 a draft set of

Hydrocarbon Measurement Engineering Competencies was released via the BP Competency on Line System [10].

This was the first explicit set of Measurement Engineering competencies supplementing the Measurement skill set identified in the Commercial Network HVR Competency set and the Flow Measurement related element of the Discipline Instrument Engineer Competency set.

The significant difference with the Hydrocarbon Measurement Engineering us that it covered Phase behaviour, Laboratory and analytical Techniques and Measurement Uncertainty. On the release of these competencies the AzSPU Metering Technical Authority undertook Measurement Competency Assessment with the participation of Metering personnel. The outcome of the Assessment session was a recommendation for training, in specific competency areas, and development in other areas e.g. HVR skills.

The assessment session took the form of a technical discussion, with pencil & paper & sketches, which started at a basic level around meter type selection for an application. The discussion then moved onto influence factors which affect meter type e.g. pressure, temperature, phase, Re number. Having identified influence factors the discussion moved around how the influence factors could be characterised and implemented.

The types of response expected were e.g.:

- use a p.d. meter for crude oil Export installed in accordance with API 5.2.
- a meter of this type should only be used on a crude oil well above its bubble point. Bubble point can be inferred from a phase diagram for the crude
- minimise influence factors by using a prover described in API 4.1, for flow rate sensitivity, and utilise pressure and temperature measurements, for fluid corrections
- pressure and temperature effects on crude oil factors can be characterised by a VCF calculated in accordance with API codes (Chapter 11) and programmed in a flow computer
- VCF is dependent on dry oil gravity which can be inferred through using a variety of ASTM methods to determine water cut or from online densitometer measurement.
- Representative samples for determining crude oil density can be obtained using a sampler design in accordance with API 8.

This example is limited to crude oil metering but it’s an important view of crude Oil Export quantity and quality. Some of the part responses are shown in Figure 8 below and suggest where there is a satisfactory level of knowledge or where there may be opportunities for development and training.

Figure 8a depicts vortex shedding and indicates period between vortices as being relevant to flow measurement. Figure 8b indicates the response to a query regarding water cut techniques and limits of applicability. Figure 8c identifies the key elements in a gas analyser / sampler loop. Figure 8d represents a phase diagram with the key points and areas annotated.

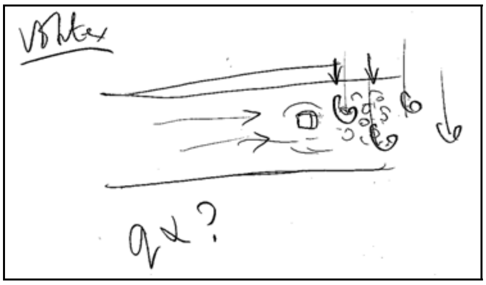

Figure 8a - Vortex Meter Principle of Operation

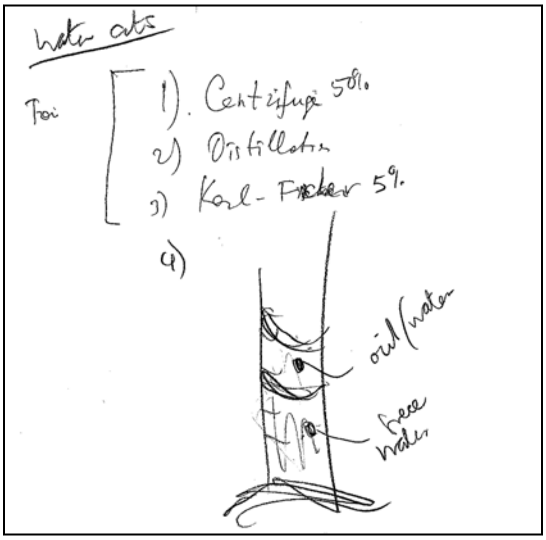

Figure 8b - Using a Measuring Cylinder for high water cuts

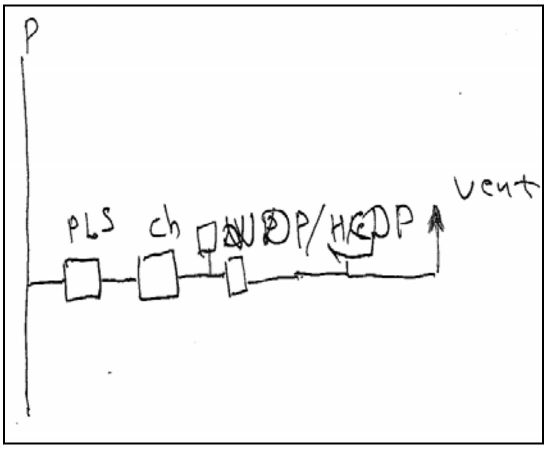

Figure 8c - Key Elements in a Gas Analyser / Sampler Loop

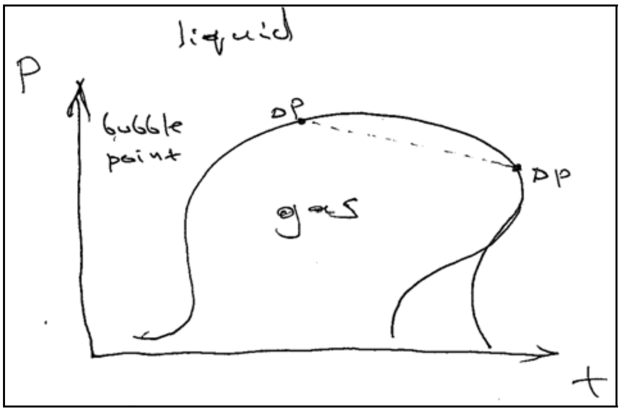

Figure 8d - Phase Diagram

7.0 DEVELOPMENT OF A REGIONAL PROVER CALIBRATION SERVICE

Azmetco is the Principal provider of metering services in Azerbaijan and has its roots in the Joint Stock Company of 'Complex Adjustment and Automation', established in 1981. 'Complex Adjustment and Automation' serviced the Regional oil industry in Azerbaijan, Georgia, Kazakhstan and Turkmenistan.

Following Azerbaijan's independence in 1993, 'Complex Adjustment and Automation' became an autonomous section of the State Oil Company of Azerbaijan Republic (SOCAR) and worked with many Regional Oil companies including Salyan Oil, Shirvan Oil, Binagadi Oil, AzGerneft, Karasu Operating Co. and in 1998, Azerbaijan International Oil Company. As it stands today, Azmetco was formed as an Open Joint Stock Company through the second Program of State Property Privatisation in 2002. [11].

7.1 Metrological Infrastructure in Azerbaijan Republic

In 2004, a BP review of Regional calibration capabilities identified that Regional calibration practices generally met industry accepted standards, however there were concerns regarding calibration equipment traceability and lack of detail in procedures. Then, as now, the

Azerbaijan Republic State Agency of Standardisation, Metrology and Patency (AzGOST) [12] maintained a register of metrological equipment and licensed the equipment for use in the State of Azerbaijan. Other than this activity there was no recognisable National Metrology Institute (NMI) or metrological infrastructure. The service offered by Regional providers centred on calibrating equipment using UKAS type accredited, calibrated 'standard' equipment and asserting that this provided traceability. None of the facilities visited carried accreditation from an independent Authority.

It should also be borne in mind that the former Soviet Union, whilst signatory to the Metre Convention, did not participate in what would become the International Laboratory Accreditation Co-operation (ILAC) [13] Mutual Recognition Agreement (MRA) and, as such, standards could be viewed as Regional, trading standards. The GOSTandard legacy has persisted in the former Soviet Union states, the Commonwealth of Independent States (CIS), although a European Union sponsored Project, Inogate [14], has promoted technical standards harmonisation across the Black Sea and Caspian Region. Participants in this programme are the 12 member states of the Eurasian Interstate Council for Standardisation, Metrology and Certification (EASC) [15] also known as MGS - межгосударственный совет по стандартизации метрологии и сертификации. The principle objective of the EASC is to develop common Standardisation, Metrology and Certification in support of trade in the CIS common economic area.

In the more specific area of Metrology, the Euro-Asian Cooperation of National Metrological Institutions (COOMET) [16] comprises 11 of the EASC member countries (excluding Turkmenistan) NMIs but also includes the NMIs of: Bulgaria; Cuba; Germany; DPR of Korea; Lithuania; Romania and Slovakia. The objectives of COOMET are stated as:

- assistance in effective addressing the problems relating to uniformity of measures, uniformity of measurements and the required accuracy of their results;
- assistance in promoting cooperation of national economies and eliminating technical barriers in international trade;
- harmonisation of activities of metrology services of Euro-Asian countries with similar activities in other regions.

One possible future metrological model for the Region is accreditation of calibration facilities by a Regional body, such as EASC, through an MRA between COOMET member states. The obvious link to standards harmonisation of metrological activities out with the Region would seem to be ISO17025 accreditation and participation in ILAC.

7.2 Developing AzMetco Metrological Capability

The metering requirements of BTC pipeline, crossing 3 countries to International markets, introduced a new level of International, as opposed to Regional, measurement compliance, the interpretation being that accepted industry practice required traceability to National standards level.

Several options were considered to develop a 'traceable' prover calibration service in Region. The options were:

1. A master meter / prover rig owned & operated by BP
2. A master meter / prover rig owned by BP, operated by a third party
3. A master meter / prover rig owned and operated by a Regional market place service provider

Economic modelling showed no particular cost advantage to BP by any option, but impartiality and Regional service development requirements was clearly led by Option 3. Having previous Regional experience, Azmetco were awarded a five year single source contract to calibrate BP AzSPU provers, subject to an agreed development plan

It was agreed with Azmetco that they would develop their prover calibration service in three stages:

- purchase measures, with National standards traceable certification
- purchase a new, smaller volume prover
- develop a gravimetric calibration capability

To facilitate the development program, Azmetco were the first local company to receive a loan from the Supplier Finance Facility (SFS). THE SFS is a multi million dollar fund set up BP, co-venturers and the International Finance Corporation, to provide loans to local companies awarded BP contracts.

In 2005 Azmetco purchased 2 Seraphim measures of nominal volumes 500 and 100 litres calibrated by NIST. The cans were used to calibrate their existing 5m^3 volume pipe prover and would be used to calibrate a new small volume pipe prover when it was delivered in Region, eventually in 2007. The gravimetric calibration facility is currently under development in AzMetco Ramana facility.

Water draw of the 5m^3 prover was carried out in July 2005 using the two new measures. The, lengthy, procedure required 5 fills of the 500 litre measure and 4 fills of the 100 litre measure per volume pass. The average deviation in volume between the prover volumes in use and the new water draw calibration volumes was 0.013%, with repeatability, in individual volumes, of 0.022%.

The new, nominal volume 1.1 m^3, pipe prover was built by Daniel-Emerson in Houston and was received by Azmetco in 2007. It was calibrated by water draw against the new measures in Region, prior to use. The results of the small volume prover water draw calibrations, for the last 3 years is shown in Figure 9.

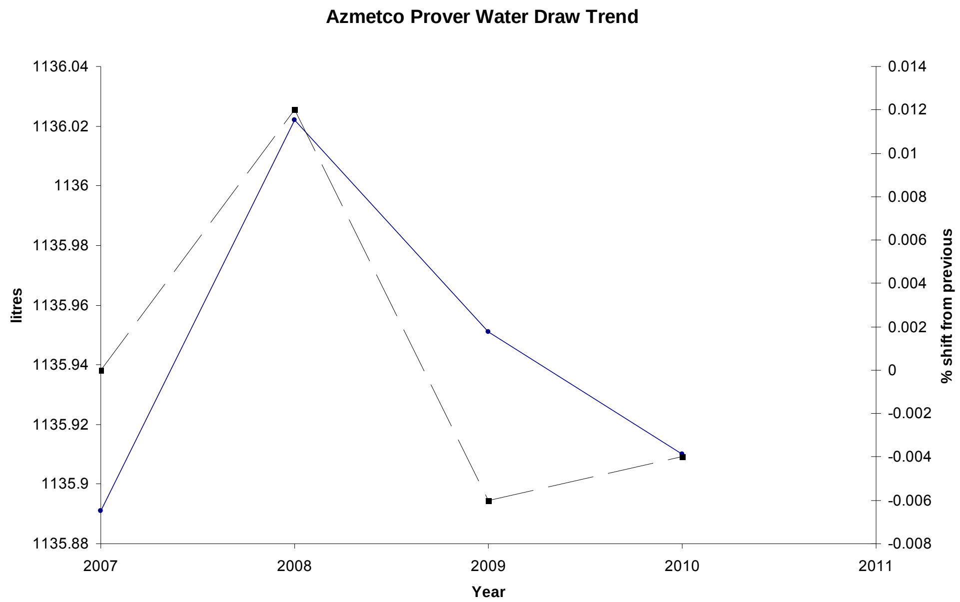

Figure 9 - Azmetco Prover Water Draw Trend

Unfortunately the seraphim measures were not received in Region in time to support calibration of the BTC pipeline PSA1 meter system prover in Sangachal Terminal. A European vendor was mobilised by Project to calibrate the prover in time for first oil operation, in 2005. The PSA1 meter prover was then calibrated by Azmetco in 2008. All four calibrated volumes agreed to within 0.005% of the European Vendor’s 2005 calibration.

The water draw trend and the calibration comparisons of the PSA1 prover, demonstrate exemplary calibration achievement by the Azerbaijani company, Azmetco, and are indicative of the level of skills and expertise they bring to the oil industry in the Black Sea and Caspian Region. Most recently Azmetco have travelled to Turkey to calibrate the prover at the Ceyhan Marine Terminal.

7.3 Recent Metrological Development in Region

At the time of writing there is a joint venture between a European service provider and CIMEX, an Azerbaijani company. The objective is to develop an ‘in Region’ calibration facility with ISO17025 accreditation for the calibration of General Plant Test Equipment and Fiscal Metering Test Equipment. The Plant Test Equipment is site calibrated to UKAS standards, however the Fiscal Metering Test Equipment is returned to the UK for calibration at an accredited laboratory.

Whilst the set-up of the laboratory may be straightforward, what is not so clear is how accreditation can be awarded given that there are no legal entities in Azerbaijan capable of conferring ISO17025 accreditation

8.0 EQUIPMENT RATIONALISATION

Across the BP operated systems in the SPU, there are:

- Of the 57 installed p.d. meters: 28 no. are 12” of interchangeable cartridge type and 17 no. are 16” of interchangeable cartridge type.
- Flow computers are standardised on OMNI model 600 or model 3000 with an installed base of 80 flow computers
- around 94 ultrasonic meters (usm) with two main types of variants - around 60 Khrone UFM 500 series and 15 Panametrics GF868 series. The remainder include around 10 Controlotron 1010 series clamp on meters.

There is apparent scope for rationalising spares e.g. rather than hold 9 off 16” spare p.d. meter cartridges distributed across 3 sites at a cost of around 100,000 USD per cartridge, could we hold, say, 6 centrally and call them off to site when required?

Similarly, there are 18 flow computer chassis, power supply units and cpu boards held across 7 Assets. To populate these chassis there are around 60 spare plug in boards. With an estimated mtbf of 192,300 hours this might be considered excessive, albeit at relatively low cost at an average of around 700 USD per board [17]. Would a local service provider be willing to hold a defined number of spare pre-configured flow computers and also manage turnaround of failed units?

The usms are installed mainly as fuel loading meters and in leak detection systems (lds). There is some redundancy in the lds the usm applications are largely non-critical. The spare that are held are fuses / cover gaskets / replacement transducers. Rationalisation of this equipment isn’t considered to be of great Operational or cost benefit. Currently, the usm strategy is to call out vendor service reps as required. With the exception of the clamp on types, used for booster pump control, no spare meters are held. [18]

With potential equipment rationalisation in mind the following considerations arose:

- BP approached potential ‘partners’ who might be interested in managing spare holdings i.e. local agents acting as Regional Sales outlets for the Vendors concerned. None of the ‘partners’ approached indicated particular interest in investing in a spares management service. Without a commitment to hold Regional spares, hence reducing lead time, it is difficult to see what ‘added value’ this type of service could deliver
- Identical spare parts, in any one Asset, could have different ownerships and so different cost codes for replacement parts with automated re-order levels. Spare parts used for Group A owned systems which were taken from Group B spares holdings could, without

intervention, result in cost allocated against Group B, although ultimately the cost is re-imbursed by the State through SOCAR.
- Cross border movement of spares, between AzSPU Assets, incurs Customs considerations e.g. are the spares permanent or temporary Exports / Imports. These generally incur cost and potentially lengthy border hold ups if not straight refusal to Export the parts.

On balance, rationalisation of equipment is, probably, best achieved on an Asset basis within International borders.

9.0 CONCLUSIONS

9.1 The SPU Management of Measurement Functional Model

The Management of Measurement Infrastructure in BP Azerbaijan has been developed to a high level using a mixture of resources to meet specific, high level guidelines identified in a Metering Strategy.

Many of the steps along the way have been subject to strong challenge, particularly where these may have been at odds with existing local custom and practice. Consideration of these challenges, towards what is considered accepted practice in the European and North American Regions, has required reversion to a 'first principle' type rationale to satisfactorily implement development for all concerned. This has been particularly the case in the area of calibration standards and 'traceability' to International standards

The strategy functional model based on [2] has proved to be a very useful framework in identifying 'Ownerships' across several interfaces within the SPU, and external interfaces with Regional Service providers. Through this we have learned about measurement function expectations from diverse perspectives and have been able, in some cases, to set new expectations.

As a result of this, Regional Service providers have risen to reciprocal challenge and have demonstrated innovation and talent in developing and delivering their services to meet requirements on an International stage.

9.2 The Transferrable Management of Measurement Model

The achievements of the SPU Measurement function have, in many cases been 'firsts' at SPU level. This is, possibly, as the SPU structure has not been in use for very long, since around 2005. It is however probably the first time that an attempt has been undertaken to 'gel' the many facets of measurement as a 'function' from a relatively undeveloped state. This has been driven by the necessity to coordinate the activities of a relatively large measurement Infrastructure, still expanding, in a relatively short time, with little existing infrastructure.

The ISO10012 model has proved to be very flexible, and robust, in describing a measurement process, which can be embedded in a wider business context through appropriate, defined interfaces.

It is a model which could be usefully adopted for development of 'Greenfield' Measurement Operations and for 'formalising' measurement related processes within mature Organisations.

9.3 Future Work - Demonstrable OMS Compliance

The next phase of work is to consolidate the existing infrastructure and practice to demonstrate compliance with BPs Operating Management System (OMS) [19]. This will involve 'evolution' of the existing strategy [3] into a Site Technical Practice, (STP) - about 'measurement the BP Azerbaijan way', with particular emphasis on Class 2 meters.

This will be supported by incorporating reference [8]. the Operational Management procedure and by achieving a consensus and adoption of formal kpis

10 ACKNOWLEDGEMENTS

As the reader might imagine this work has been the considerable effort of many people, at various times, over several years. The authors thank BP Azerbaijan for allowing the publication of this story and also those who have participated in workgroup activities and, ergo, followed the strategy.

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