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RESTORING INTEGRITY TO AGED PETROLEUM PRODUCTION FACILITIES

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ABSTRACT

BP and its local predecessor Amoco have produced oil and gas off the east coast of Trinidad for over 30 years. This production originates from eight offshore fields and is transported to onshore terminals through an extensive pipeline network. Gas is further shipped for domestic use or LNG production. Oil is temporarily stored onshore and then tanker loaded for export. Despite excellent business success for the operator and nation, maturing production, long service time and constrained resources have taken a toll on the technical integrity of facilities.

In late 2000, a major program to restore integrity was developed, resourced and implementation begun. The restoration strategy was based on a four-step process involving assess, restore, upgrade and sustain. The program addresses the technical integrity of all assets including offshore topsides, subsea structures/pipelines, onshore terminals, tankage and oil/gas exports systems. It also included enhancements to process safety protective systems and development of a comprehensive major accident hazards management system.

This paper outlines the many problems, solutions, challenges and successes of the integrity restoration program. It describes the required organizational commitment to a multi-year improvement campaign and a shared vision of sustained, world-class integrity management. In its third year, the program has had significant accomplishments, although there is still much to do. Overall, it has been a strong contributor to continued business success both now and into the future.

INTRODUCTION

BP's (formerly Amoco's) Teak, Samaan and Poui fields were among the first offshore oil developments in Trinidad, with production start-up in the early 1970s. These multi-platform fields were tied by subsea pipelines to an oil processing terminal, tankfarm and tanker-loading export system at Galeota Point in the southeast corner of the island. The operator expanded into gas production in the early 1980's with development of the Cassia field. Additional gas/condensate resources, with associated light oil, were developed in the early 1990s

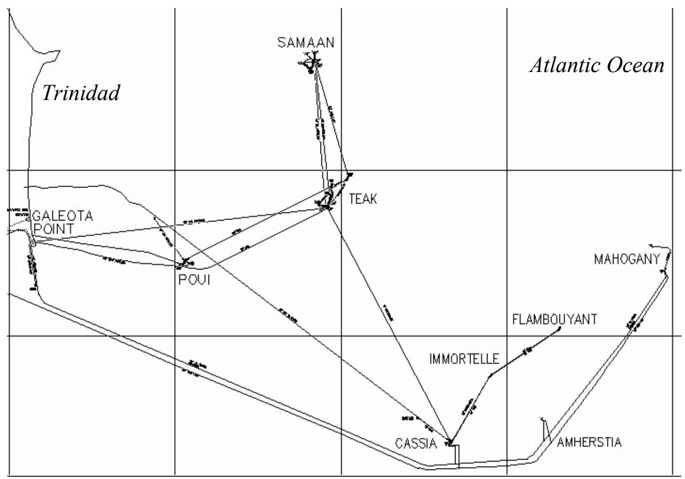

Figure 1 – Overall layout of major BP Trinidad offshore assets.

at Immortelle & Flamboyant. Build pace again accelerated in the late 1990's after establishment of an onshore LNG consortium, with Mahogany and Amherstia fields developed and put onto production, and the Kapok and Cannonball developments in progress.

The net effect of the expansion history noted above was the accumulation of vast facilities assets for the operator, consisting of 26 offshore structures, 50 pipelines and two onshore oil and gas terminals. Overall layout of the offshore infrastructure, currently producing 77,000 bbls oil/day and 1.7 billion cubic feet gas/day, is shown in Figure 1. Of note is the wide diversity, both oil and gas production, old and new, low-pressure and high-pressure, etc.

The investments made by the operator in Trinidad's oil and gas industry have been a huge success by any standard. However, maturing production and equipment ageing have gradually developed a new set of challenges associated with the technical integrity of the facilities. In addition, the former resources and diligence devoted to integrity management were often as cyclic as oil and gas prices themselves. Despite many well-intentioned individual efforts, management and scope of historical integrity programs were insufficient for long-term sustenance. With a growing number of integrity-related near-misses and minor hydrocarbon leaks, senior management eventually decided the situation needed serious rectifying. In addition, new corporate standards were developed that were well above those that could be met by the Trinidadian operations. Following several high-level surveys, establishment of a detailed integrity improvement program was approved. Initial implementation began in 2000, with momentum building yearly. What follows is a description of the ongoing work and its many successes and challenges.

TECHNICAL INTEGRITY ASSESSMENT

In the spring of 2000, on-site evaluations were made by a team of integrity management experts. These investigations included review of records, plant inspections and interviews with a diagonal cross section of management and staff. The following observations were made:

- A variety of integrity-related maintenance, inspection and chemical treatment activities had been implemented throughout the years, but with little coordination of efforts.
- In fact, the operator had been considered a pioneer within the corporation for its use of stainless steel production tubing and wellheads at Cassia in the early 1980s (e.g., 13Cr tubing, CA6NM/F6NM valves) [1,2].
- Corporate staff had performed regular corrosion surveys of Trinidadian operations; there was often a spurt of integrity-related actions following these surveys, but many recommendations were never implemented (e.g., pipeline pigging).
- The intense east-coast sea spray and insufficient painting maintenance had led to serious deterioration of piping in the onshore oil terminal and offshore topsides (particularly in smaller diameters and at pipe supports). Secondary structures (decking, railings, stairs, etc.) were similarly deteriorated.
- Numerous plant rebuilds had been done over the years without a formal Management of Change (MOC) process. This led to sub-par construction (e.g., numerous threaded connections into pressure piping) and many times, a defeat of the intent of process safety protective systems. Engineering drawings and safe-charts had not been updated following most modifications.
- Little, if any, testing or maintenance of protective devices had been regularly performed over the years. Records of such work were virtually absent.
- The oil terminal tankfarm had a series of deficiencies, including antiquated tank design (single seal floating roofs and insufficient fire-fighting capabilities), annular plate corrosion problems, a history of rim-seal fires and associated tank damage. Topographically, the plant suffered from close tank spacing, loss of individual tank containment capability by the existing earthen berm walls and poor drainage.
- Maintenance of older subsea pipeline systems by pigging and chemical treatments was not performed; in fact, most pig traps had been removed over the years. The Immortelle and Flamboyant pipelines had been installed without pigging equipment.
- Subsea jacket inspections and repairs had been done, but only on an intermittent basis.
- Corrosion inhibition treatments were performed on some systems, but with little monitoring to optimize or evaluate effectiveness.
- Inspections were irregularly performed and only then on main pieces of process equipment. Of even greater concern, inspection-generated punch-list repairs were not regularly acted upon, so there was a large back-log of remedial work needed.
- No serious hazards evaluations had been performed for older facilities since their initial design.

Based on these observations, it became clear that it would be a formidable undertaking to improve integrity standards in the business unit. In order to prioritize work efforts, a qualitative risk matrix was developed as shown in Figure 2. To conventional practice, risk was

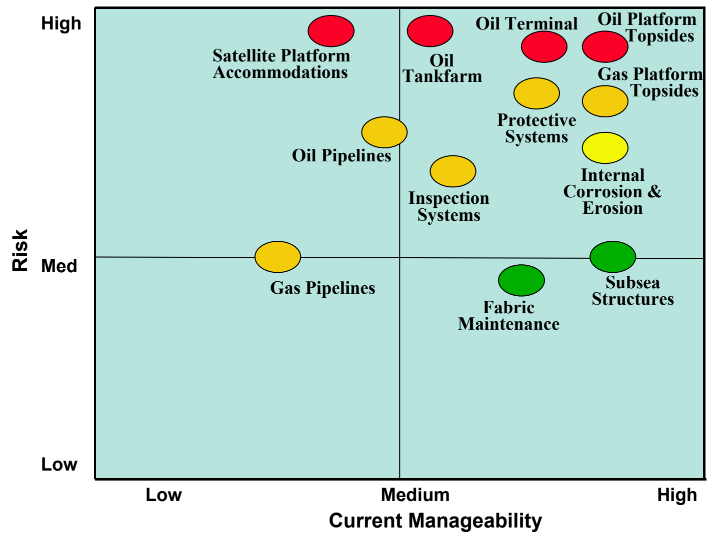

Figure 2 – Year 2000 qualitative risk matrix.

defined as the product of likelihood and consequence of failure, from safety, environmental, business and reputation perspectives. Likelihood of failure was estimated based on existing records and recollections of staff. High likelihood was assigned to events which had happened at least once in the prior two years. Medium and low likelihoods were similarly defined as the 2-10 year range and greater than 10 years (or never), respectfully. Interestingly, a major historical cause of hydrocarbon leaks was due to external corrosion (versus process corrosion), particularly in smaller diameter piping. In fact, experience has shown that unprotected steel (such as flanged connections) exhibit substantial deterioration within two years due to the warm, humid conditions and substantial Atlantic sea-spray. Hence, age of facilities and current state of external corrosion protection figured prominently in likelihood of failure.

Not surprisingly, events associated with high-pressure gas releases and major business interruptions (e.g., terminal or tankfarm events) were categorized as high consequence. Although potential oil leaks themselves were generally regarded to have medium consequences in the model, most oil production facilities use high-pressure gas lift, hence possible failures of these systems placed the older oil production plants into the high-risk category.

Manageability in Figure 2 was estimated based on technical difficulty and time to implement effective corrective actions. For example, once scopes of work were assembled and contracts awarded, terminal and offshore topsides punch-list repairs, blasting and painting were relatively easy and quick to execute, hence, manageable. By contrast (as described below), lack of existing pigging facilities made pipeline integrity work complex, time-consuming and costly, i,e., less manageable.

To keep the initial work focused, it was agreed that a priority would be to restore plant to its design level of integrity assurance first, before looking for systematic upgrades. Based on this philosophy, action plans were developed and required resources and budgets estimated. By the autumn of 2000, the technical integrity improvement program was underway, albeit only within its first small steps.

INTEGRITY IMPROVEMENT IMPLEMENTATION PLAN

The work mode adopted to implement the integrity improvements consisted of a simple four-step process:

Assess => Restore => Upgrade => Sustain

Two new organizations were built and staffed to execute the plan: A Technical Integrity (TI) Project, to mainly handle the assess, restore and upgrade steps, and a Corrosion-Inspection-Chemicals (CIC) Team to handle sustain. In fact the teams have worked closely and cooperatively, so both have been involved in the entire process.

Sub-project teams were then formed as:

- <u>Platform topsides</u> – to perform punch-list repairs and other corrective actions.
- <u>Subsea integrity</u> – to perform remote operated vehicle (ROV) and diver-assisted inspections and repairs to structures and pipelines.
- <u>Pipelines</u> – to design/install pigging infrastructure, to pig pipelines clean and inspect by intelligent pigging.
- <u>Terminal and Tankfarm</u> – to perform punch-list repairs and corrective actions on onshore piping systems; to sequentially implement oil tank repairs/upgrades and to correct berm civil problems.
- <u>Protective Systems</u> – to implement systems for protective device management based on API RP 14C [3] and to perform repairs and upgrades.
- <u>Inspections</u> – to build complete process system piping/vessel registers and from that, a comprehensive inspection plan.
- <u>Corrosion Control & Chemical Treatments</u> – to implement vastly improved monitoring and chemicals management systems.
- <u>Major Accidents Hazards Management System (MAHMS)</u> – to develop and implement a comprehensive MAHMS system and to propose process, people and plant remedial measures for further integrity improvements.

These teams subsequently developed detailed project plans, confirmed funding and began implementation through use of internal and a large number of foreign and domestic contractors and equipment. Each of these fields of endeavor is discussed in more detail below.

PLATFORM TOPSIDES INTEGRITY

Systematically doing offshore topsides punch-list repairs, which were among the most urgent activities based on risk assessment, was originally envisioned to be relatively straight-forward. However, for a variety of reasons, the historically liberal live-plant hot work policy was changed to a virtual hot work ban soon after project kick-off. Project team members were quick to adjust by organizing work into planned turn-arounds (TARs), for which facilities are shut-down, flushed and gas freed prior to hot-work. But in this execution mode, the TARs soon became major activities, with a large variety of work requests input into scopes. Some of the work challenges faced were:

- Planning and executing more than a few major TARs a year, due to limited people resources.
- Ensuring appropriately experienced contract crews were deployed on TARs for safety and efficiency reasons.
- Working on a 24-hour basis and housing sufficiently large crews offshore.
- Other logistics for TARS, e.g., porto-camps, materials, lighting, auxiliary power, etc.
- Assurance of permit-to-work and MOC compliance, as well as safety aspects of lifting operations and working below cellar decks over open water.

The following items were typically addressed during TARs:

- Repairs to and sectional replacements of process and fuel gas piping systems, particularly associated with supports. Figure 3 shows a typical "before" example.
- Removal and/or seal welding repairs to threaded connections into pressure piping.
- Replacement of defective shut-down valves (SDVs), especially for pipeline risers.
- Replacement of fuel gas scrubbers, Figure 4.

Figure 3 – Temporarily repaired fuel gas line replaced during offshore TAR.

Figure 4 – Installation of replacement fuel gas scrubber during offshore TAR.

- Substantial hot-work fabric maintenance, including decking, stairs, ladders, handrails and wind-walls.
- Installation of numerous coupon, probe, sampling and chemical injection ports on behalf of the CIC team.
- Installation of access fittings for green-house gas reductions.
- Structural repairs to areas of jack-up or supply vessel collisions.
- Installation of pigging facilities and riser retrofits (see below).
- Change-out of defective control and isolation valves.

Within three years, a total of 16 platforms have had TARs, resulting in correction of most defective items. The work, which has involved hundreds of thousands of man-hours, was accomplished without lost time accidents or greater, with just two first aid cases (although near-misses were common). This mode of punch-list repair execution has now become a norm for the operator and it is planned that long-term technical integrity will be maintained by planned TARs well into the future.

SUBSEA INTEGRITY

As mentioned above, subsea surveys had historically been sporadic before the year 2000. In addition, these surveys, and limited remedial repairs, concentrated on platform structures, i.e., virtually no pipeline surveys had been performed. In addition to the lack of integrity assurance, precise locations of the majority of the pipelines were unknown.

The CIC Team took the lead to rectify the year 2000 situation. This began by risk ranking the various structures and pipelines based on age, jacket type/robustness, inspections performed to date, leak history of pipelines, etc. The result was a subsea inspection program with varied inspection frequencies based on risk ranking. Unfortunately, it was found that to reach an acceptable baseline, several years of costly diving and remote-operated vehicle (ROV) surveys would be required.

The proposed subsea program was further complicated by increasing corporate safety standards for diving and marine operations. Several decisions were reached in this regard to govern the subsea work:

- Diving operations would no longer be conducted from platforms, as had been a prior practice.
- Use of anchored diving vessels would be avoided as much as possible, with preference given to redundant dynamically positioned vessels (DP2 minimum).
- The requirements of IMCA D Series would be adhered for all manned subsea operations [4].
- Third party representation would be applied to all subsea work.

With the above as a basis, TI Project staff project managed the work, which has thus far resulted in substantial diving campaigns in both 2002 and 2003, with additional campaigns planned for the future.

Scope of work for the diving campaigns have included the following typical items:

- Surface and saturation diving/ROV inspections of subsea structures, including cathodic protection (cp) measurements,
- Steel and grout repair of structural cracks and damage; the latter generally having resulted from supply vessel impacts,
- ROV surveys of pipelines, including cp profiles,
- Pipeline repairs to anchor drags using spool piece connector systems,
- Grout repairs of pipeline free spans and weight-blanket stabilizations.

Within 2004, integrity survey "catch-ups" will have been accomplished for both structures and pipelines. In the future, these operations will be based on a strategy of major efforts every 3-5 years, versus yearly programs. The driving force for this strategy is the high mobilization/de-mobilization costs associated with vessels and crews capable of the high-standards required, which are not normally based in Trinidadian waters.

PIPELINES

Although the operator has 50 individual pipelines, mainly subsea, the vast majority of these are short "infield" lines, i.e., carrying production, low-pressure gas, high-pressure lift-gas and/or injection water within a single field development (i.e., from satellite platform to main complex or vise versa). However, 12 of the system's pipelines are critical links in transporting oil and gas to shore and hence to sales export. The newest of the pipelines were installed in the late 1990s with well-engineered and constructed pigging facilities. These lines are routinely pigged and have been recently base-line inspected by intelligent pigging. However, the 9 remaining major oil and gas lines, with vintage from early 1970s to early 1990s, either had inadequate or missing pigging facilities at kick-off of the integrity upgrade program in late 2000. There had been no maintenance pigging and limited chemical treatments on these pipelines throughout their service lives. It would clearly be a major job to provide integrity assurance for these pipelines.

Figure 5 – Two 18" pig traps installed on Poui. Note angled gate valve (grey) on the right trap.

The 9 main oil and gas lines needing retrofit of pigging facilities, subsequent heavy refurbishment pigging and intelligent pig inspections are associated with the Teak-Samaan-Poui (TSP) oil fields and the Cassia-Immortelle-Flamboyant (CIF) gas/condensate/light oil fields. Risk ranking of all pipelines in the system based on estimated internal corrosivity, age and consequences of failure showed the TSP oil lines to be highest risk, so project work was started there.

A more detailed review of experiences preparing for and pigging the TSP oil pipelines can be found in another publication [5]. However, a few of the most important accomplishments and learnings include:

- Time, money and commitment needed to retrofit 30 year old pipelines with pigging facilities, progressively pig clean and inspect by intelligent pigging should not be underestimated; they are truly substantial (e.g., $1-3 million per pipeline).
- It was necessary to change-out offshore risers on the oil pipelines; this because there were a large number of hot-tapped tees which could hang-up pigs (new risers had properly barred tees).
- Experiences with hard-seated, expanding wedge gate valves have been excellent, even after repeated openings and closings against heavy sand and scale accumulations. Another advantage is they provide double-bock and bleed (DBB) isolation with a relatively small footprint.
- Enormous quantities of debris were removed from the old oil lines by progressive pigging For example, 40 metric tons from two parallel 1.9 km 8-inch lines and 115 metric tons from a 22.5 km 18" pipeline.
- Hard scales made repeated pigging with descaling tools necessary (e.g., 88 pig runs were required for the 18" pipeline noted above).
- A separator or similar vessel is required on the receiving end of pipelines to collect debris and enable continued production and oil sales; if a suitable vessel does not exist, it may have to be built at great expense and time (as was the case here).
- For low-pressure pipelines, ASME B-31G will allow substantial wall loss with confirmed fitness-for-service [6].
- Once cleaned, it may be possible to get years of safe operations from even heavily damaged pipelines by combining routine pigging and corrosion inhibition chemical treatments [7, 8].

Some representative photos from the oil line rehabilitation works are shown in Figures 5-8.

Figure 6 – New separator at the Galeota Point oil terminal to collect pigging debris from incoming pipelines.

Figure 7 – Receiver on Poui platform with pigged debris.

As work progressed on TSP oil pipelines, engineering, procurement and construction (EPC) activities were begun for CIF gas and produced fluids pipelines. These activities are still underway, so no pigging experiences can yet be reported. However, EPC has involved an entirely different set of problems than those enountered with the oil lines. Many of these problems are related to an apparent early 1990s fabrication philosophy to install facilities quickly and cheaply. Problems experienced include:

- The Flamboyant and Immortelle pipelines were constructed without pigging equipment; what's worse, the platforms are small and tightly packed, with limited space for new facilities.
- To add pig traps and associated valves, large cantilevered deck extensions were required, dramatically increasing expense.
- Because heavy sand accumulations are expected in certain pipelines, the temptation of installing vertical pig traps was avoided. Although costs would have been greatly reduced, serious operational issues associated with removing debris from vertical receivers would have resulted.

Several of the CIF pipelines had ocean floor configurations including tees, which would prevent pig passage (apparently for future tie-in capability). At great expense, it was necessary to remove these subsea components and replace them with elbows

Figure 8 – Receipt of intelligent pig on Poui platform.

- to enable pigging. This was accomplished using connector/spool piece technology.

The above construction activities have resulted in significant production outages due to the operator's hot-work policy. This has been a test of the staff's and management's commitment to safety and integrity first, but clearly, a test the organization has passed.

OIL TERMINAL AND TANKFARM

As a process, the Galeota Point oil terminal is quite simple, basically consisting of water/oil separation through a series of separators and heated water wash tanks. Through the years, the terminal had suffered similarly to offshore topsides, with inadequate painting maintenance and sub-par facilities modifications. Needed refurbishment consisted mainly of grit blasting and painting, although frequently the requirement for metal repairs was also identified. For the vessels, these were systematically removed from service, cleaned, internally inspected and then repaired as necessary. In addition, substantial piping and valve repairs and replacements have been made to the terminal fire water system.

Restoring integrity to the oil tankfarm at Galeota Point is still ongoing and has been complex, time consuming and expensive. The tankfarm consists of three 500,000 bbl tanks and two 250,000 bbl tanks. These were constructed in the early 1970s using single deck annular pontoon roofs, single pantograph seals and single jack-knife drains. Several potentially severe incidents have occurred through the years with these tanks, including at least two lightning-induced rim-seal fires, roof flooding due to blocked drains, over-filling (before high-level alarms were fitted) and annular floor plate corrosion, which led to at least one leak. In addition, the berm civil works isolating tanks from each other had been eroded/broken down over the years.

Scope of work to sequentially repair the tanks and tankfarm civils consists of:

- Cleaning of tank bottoms sludge and thorough internal inspections.
- Replacement and repairs of corroded annular plates.
- Installation and upgrading of low and high level alarms.
- Upgrade and/or installation of secondary roof seals to reduce emissions and the likelihood of rim seal fires, Figure 9.
- Installation of secondary roof drains, improved pontoon manway covers and upgraded rim seal foam firefighting systems.
- Upgrade of cp protection and installation of lightning dissipation systems.

Figure 9 – Secondary floating roof seal on oil storage tank.

- Complete re-build of civil berm works, including re-install of drainage systems.

Refurbishment of the first large tank was completed in May 2003 and in fact, required over two years work for the entire job. Clearly the repairs and upgrades to the tankfarm will require several more years of continued commitment.

PROTECTIVE DEVICES

As mentioned above, numerous problems were found in year 2000 with the management of process safety protective devices. These were systemic in nature, to the point that P&IDs were no longer representative of actual equipment due to multiple, undocumented modifications through the years. Testing of certain devices was performed through the maintenance management system, but for every device handled this way, several were over-looked and therefore not regularly tested or maintained.

Because of American design and analogy to Gulf of Mexico facilities (albeit larger than most USA offshore plants), an early decision was made to implement API RP 14C [3] as the guideline requirement for the operator's Trinidad safety systems. One of the early hurdles was to update all P&ID drawings to reflect actual conditions and from there, to build a complete registry of protective devices. In fact, over 8,000 items were finally located. Further, once existing systems were reviewed, numerous gaps to API RP 14C compliance in both design and testing were found. A comprehensive upgrade program eventually resulted, including replacement of outdated systems with those based on programmable logic control (PLC).

The API RP 14C project has in fact been most formidable and continues to this date. Major accomplishments include:

- Completion of a comprehensive registry of protective devices.
- Update of associated P&IDs and "Safe-Charts."
- Full implementation and population of a proprietary on-line database for protective device testing and maintenance.
- Monthly tracking of protective device testing compliance.
- Implementation of acoustic leak tests for valve sealing assessments.
- Actuator/valve alignment checks and adjustments, greatly reducing the number of leaking safety valves onshore and offshore.
- Replacement of numerous defective safety valves, most commonly with hard-seated equipment due to proficient sand production from Trinidadian reservoirs, and selected upgrades to actuators.
- Definition of upgrades required for full API 14C topsides compliance at the older oil production platforms.
- Implementation of new shut-down PLCs throughout the oil fields.

Interestingly, some of the API 14C gaps identified in gas system shut-downs (SDs) are not easily rectified through conventional means, e.g., low-pressure SD devices would not react until a massive gas leak had occurred. This has resulted in strong interest in acoustic leak detection; this topic is briefly discussed below in the section on Major Accident Hazards Management.

INSPECTIONS

Inspection programs in-place in the year 2000 could best be described as rudimentary. Major pieces of critical process equipment were logged into a scheduling data-base and therefore were, for the most part, regularly inspected. However, not only did the current system lack sufficient rigor to be comprehensive in process plant, but numerous auxiliary systems such as utility air and water were absent from the data-base and therefore received no regularly scheduled inspections.

Following re-organization of inspection activities into the CIC Team mentioned above, work was begun in earnest to improve upon the situation. Some of the achieved highlights include:

- Recruitment of additional inspection technologists.
- Tracking of planned versus actual inspections was begun and immediately highlighted significant gaps, as well as opportunities for improvement.
- A library facility was completed which filed together all inspection data, drawings, reports and failure investigations.
- The electronic inspection database, including a complete piping and vessel registry, was fully populated.
- A pressure vessel registry program identified over 500 pieces of equipment which were not in existing records and consequently were not getting inspected; note that the majority of these were small vessels such as air receivers and knock-out pots.
- Basic ultrasonic testing (UT) training was extended to operations personnel.

As mentioned above, one of the major integrity weaknesses of the operations was punch-list repair back-logs (identified by inspections) not being acted upon in a timely manner. Although certain critical jobs can be executed quickly, the majority of punch-list items are now logged and provided to TAR teams during scope of work preparations. Most items must wait some time before being acted on, but the TARs are quite effective in ensuring inspection generated lists eventually received required handling.

CORROSION CONTROL & CHEMICAL TREATMENTS

Similar to the inspection program status, numerous corrosion and chemicals related activities were in place in 2000, but lacked a systematic approach. In addition, limited monitoring ability did not allow corrosion control and chemical treatment systems to be optimized. Because of the need for hot-work to install monitoring access, this situation could not be immediately corrected. Further, the largest historic internal threat, that of flow-line erosion-corrosion, was under-estimated in its breadth (oil assets with increasing GOR and high-deliverability gas assests), as well as its aggressiveness.

The CIC team was required to attack the above situation along several fronts and within a few years, had succeeded in the following:

Figure 10 – Duplex stainless steel flowlines and production manifold on the Kapok platform.

- Development and implementation/integration of internal corrosion control and coupon monitoring strategies.
- Gradual installation of major upgrades in corrosion coupon and chemical injection access fittings on all platforms.
- A record number of corrosion coupons processed.
- Identification of the role of acetic acid in the enhancement of internal corrosion rates [9].
- Development and roll-out of a Corrosion Awareness program.
- Organizational focus on leak reporting improved responses to ~ 100%.
- Increased used of jellied-petroleum wraps for external-environment protection of flanges and fittings.
- Incorporation of corrosion and materials lessons learned into the new platform projects. One highlight of these is the application of duplex stainless steel for the Kapok platform flowlines and production manifold, Figure 10.
- Evaluations of different erosion monitoring technologies [10].
- Widespread implementation of acoustic detectors for sand monitoring, with over 150 currently deployed.
- Implementation of an internal coatings program for many vessels.
- Implementation of a corrosion database to store corrosion information and correlate data with production events.
- Improved regularity of site visits to assure chemical treatment equipment is functional and dosage is correct.
- Resolution of all too frequent internal corrosion gas field leaks by implementation of a continuous corrosion inhibitor.
- Development of a new demulsifier for the Terminal process area which has resolved serious emulsion problems which occurred during late 2002.
- Upgrading of many bulky, carbon steel chemical injection fittings to stainless steel with integral double block and bleed valves.

Although numerous challenges remain in implementation and follow-through, the new corrosion control and chemical treatments strategies are making a measurable improvement in the integrity and reliability of operating plant.

MAJOR ACCIDENT HAZARDS MANAGEMENT

The initial integrity management restoration program was distilled from the opinions of several experts, incident reports, inspection back-logs, interviews with operations staff, etc. However, it was recognized that this program would at best restore the integrity of facilities to their "design" level of integrity assurance, which in most cases was vintage 1970s. At worst, this initial approach would over-look one of more integrity critical but less obvious issues. In order to improve status to corporate requirements, including demonstration of tolerable risk levels, it was decided that a more systematic approach to hazard identification and management was needed.

Within Trinidad operations, there was a cursory history on use of Process Safety Management based on API RP 750 [11]. However, shortcomings associated with applying this approach alone included limited emphasis on systematic hazards identification and consideration of process hazards only. Conversely, the more comprehensive approach to hazards management based on U.K. safety case legislation was believed to be too bureaucratic, suitable mainly for the safety specialist and prepared with the regulator in mind, particularly with respect to demonstrating risk reduction to levels "as low as reasonably practical (ALARP)." Similarly, the quantitative risk analysis approach used in the Norwegian North Sea was believed to be too focused on producing risk numbers versus risk management.

Following a comprehensive feasibility study, the operator embarked on development and implementation of a comprehensive Major Accident Hazards Management System or MAHMS. The reader is referred to a few other publications for detailed information on this project [12, 13]. Some of the main attributes of the system under development include:

- It delivers understanding about identified dangers.
- It builds on existing systems and processes.
- It influences facilities operating philosophy and organisational structures.
- It is understood, owned and used by the operator.
- It is not a new, short-lived initiative.
- It optimizes spending to reduce risk.
- It is simple, auditable, repeatable and easily communicated.
- It becomes an integral part of the way work is performed.
- It provides a system for managing dangers.
- It becomes an example for the whole of Trinidad & Tobago.

A process map of MAHMS is shown in Figure 11. As seen, the process follows a typical, "plan, do, measure and improve" cycle. Note that critical measures coming from the hazard identifications and risk analyses can be of three types, i.e., people, process and plant. The latter are currently producing a next round of facilities integrity improvement projects, with major emphases on leak, gas and fire detection, active mitigation and emergency response. Clearly it will be some time before the full benefit of MAHMS with respect to risk reduction are realized.

ESTIMATING PROGRESS

At least annually, the high-level integrity risk matrix is re-visited and adjusted. Unfortunately, the experience basis used to build the initial matrix cannot be directly used to make adjustments (insufficient time has elapsed since improvements were made). For certain facilities, recent data positively demonstrates a significant reduction in hydrocarbon leaks. Overall, however, reduced leak rate is masked by excellent response of the organization to requests for reporting of all leaks; minor leaks in the past were often inconsistently reported and investigated.

Risk reduction estimates are made from group judgments based on volume of work accomplished in a given year versus known outstanding issues. For this reason, significant risk reductions are estimated to have taken place in most areas, as shown in Figure 12. These are most notable on issues which had correctly been judged to be more manageable. As an exception, pipeline risks are currently estimated to have somewhat increased, as the infrastructure work discussed above has not reduced risk of itself (but has improved

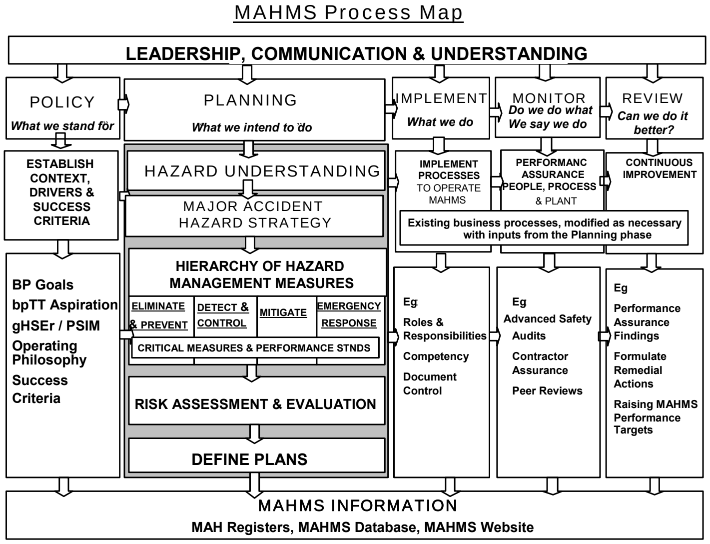

Figure 11 – Major Accident Hazards Management System process.

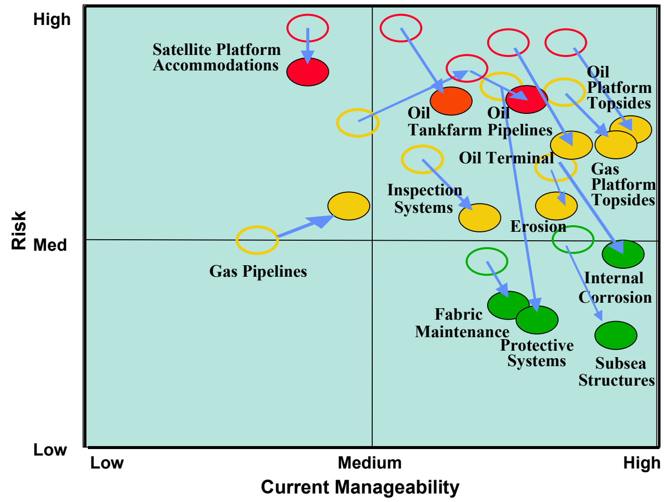

Figure 12 – Year 2003 re-assessment of integrity risks and progress.

manageability). Analysis of intelligent pigging data is required to effectively reduce risk, as indicated by the small risk drop noted for oil pipelines due to intelligent pigging of the first major pipeline in 2003.

CONCLUSIONS

- Restoring integrity to aged oil and gas production facilities is a formidable challenge involving organization, staffing, time and money.
- Once the will to improve has been achieved, the work can be initiated by fact-finding surveys followed by risk-ranking to identify activities of utmost urgency.
- The vast work required can be split into focused areas of assess, restore, upgrade and sustain.
- Major undertakings (staff, time and money) are likely best handled by deploying project teams and project management fundamentals.
- Skills and activities needed long-term are probably most appropriately handled by developing integrity management "sustain" teams.
- Even after the plan is formulated, staff are dedicated and funding provided, it can take many years to achieve the targeted integrity management improvement goals.

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