GOVERNMENT OF
WESTERN AUSTRALIA

Offshore Petroleum Safety Regulation

Varanus Island Incident Investigation

by
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Preface

In May 2009 the Western Australian Minister for Mines and Petroleum, the Hon Norman Moore MLC, decided to undertake the final phase of the investigation into the pipeline ruptures and fire which occurred at Varanus Island on 3 June 2008. He also requested a consideration of the broad safety and regulatory environment and recommendations, if necessary, to improve the Western Australian regime.

Supported by a small team of experts and secretariat members, we have reviewed documentation and information provided to us through consultation with key Australian and international regulatory agencies for offshore petroleum safety and integrity regulation and a wide range of oil and gas companies in Australia and abroad. The report is based on information generously shared with us by key agencies.

We would like to acknowledge the contributions of Professor Rolf Gubner, Chair of Corrosion at Curtin University of Technology in WA for his expertise and consideration of the likely scenarios, and Dr Richard Batt of the Australian Transport Safety Bureau for his contribution on human and organisational factors. We would also like to express our particular gratitude to members of our secretariat – Juliet Lautenbach, Joanna Bunting, David Hope and Vince D'Angelo – for their tireless efforts and hard work often extending into late nights and weekends.

We sincerely hope that this report will not only shed light on the causes of the 3 June 2008 incident, but even more importantly contribute to improving safety and regulatory effectiveness in Western Australia's offshore oil and gas industry and beyond.

KYM BILLS
Inspector

DAVID AGOSTINI
Inspector

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Acronyms and abbreviations

AEL	Apache Energy Ltd
AIMPE	Australian Institute of Marine and Power Engineers
ALARP	As low as reasonably practicable
AMSA	Australian Maritime Safety Authority
APIA	Australian Pipeline Industry Association
APPEA	Australian Petroleum Production and Exploration Association
ARRC	Australian Resources Research Centre
AS	Australian Standard
ASME	American Society of Mechanical Engineers
ATSB	Australian Transport Safety Bureau
CALM	Catenary anchor leg mooring
CASA	Civil Aviation Safety Authority
CDPP	Commonwealth Director of Public Prosecutions
CEO	Chief Executive Officer
CFR	Code of Federal Regulations (US)
CIC	Common infrastructure corridor
CMC	Change management control
COAG	Council of Australian Governments
CP	Cathodic Protection
CRA	Corrosion risk assessment
CSB	United States Safety and Hazard Investigation Board
CUI	Corrosion under insulation
DA	Designated Authority
DBNGP	Dampier Bunbury Natural Gas Pipeline
DC	Direct Current
DEEWR	Department of Education, Employment and Workplace Relations
DITR	Department of Industry, Tourism and Resources
DITRDLG	Department of Infrastructure, Transport, Regional Development and Local Government
DMP	Department of Mines and Petroleum (formerly WA DOIR)
DMPR	Department of Mineral and Petroleum Resources (WA)
DNV	Det Norske Veritas (Norwegian Standards body)

DOCEP	Department of Consumer and Employment Protection (WA)
DOE	Department of Energy (United Kingdom)
DOIR	Department of Industry and Resources (now WA DMP)
DPI	Department of Primary Industries (Victoria)
DPP	Director of Public Prosecutions
EASA	European Aviation Safety Authority
EIRG	Electricity Industry Reference Group
EPA	Environmental Protection Authority
ESD	Emergency shutdown (device)
ESJV	East Spar Joint Venture (on Varanus Island)
ESV	Energy Safe Victoria
FAA	Federal Aviation Administration (United States)
FOI	Freedom of information
FPSO	Floating production, storage, and offloading tankers
FSA	Formal safety assessment
FSO	Floating storage and offloading tanker
FTE	Full time equivalent (staffing)
GM	General Manager
GVI	General visual inspection
HAZID	Hazard identification
HAZOP	Hazard and operability
HDPE	High density polyethylene
HJV	Harriet Joint Venture (Varanus Island)
HRO	High Reliability Organisation
HSE	Health and Safety Executive (United Kingdom); or Health, Safety and Environment
IADC	International Association of Drilling Contractors
ICAO	International Civil Aviation Organization
ILI	In-line inspection (intelligent pigging)
IMCA	International Marine Contractors Association
IMO	International Maritime Organisation
IMR	Inspection maintenance and repair
IP	Intelligent pigging (In-line inspection)
IPPC	Integrated Pollution and Prevention Control (directives)
IRT	Independent Review Team
ISM	International Safety Management
ISO	International Standards Organisation
ISOM	Isomerization (process unit)

IWG	Integrity Working Group
km	Kilometre
KPI	Key performance indicator
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTIFR	Lost Time Injury Frequency Rate
LTIs	Lost time injuries
MAEs	Major accident events
MCMPR	Ministerial Council on Mineral and Petroleum Resources
MFL	Magnetic-flux-leakage
MHF	Major hazard facility
MLA	Member of the Legislative Assembly
MMS	Minerals Management Service (US)
MODUs	Mobile Offshore Drilling Units
MOSOF	Commonwealth *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996*
MOU	Memorandum of Understanding
MUA	Maritime Union of Australia
NACE	National Association of Corrosion Engineers (US)
NDT	Non destructive testing
NOPSA	National Offshore Petroleum Safety Authority
NPD	Norwegian Petroleum Directorate
NPRM	Notice of proposed rulemaking
NTSB	National Transportation Safety Board (US)
OCS	Offshore Constitutional Settlement (1979)
OCS	Outer Continental Shelf (US)
OGP	International Association of Oil and Gas Producers
OHS	Occupational Health and Safety
OHSMI	*Occupational Health and Safety Maritime Industry Act*
OPA	*Offshore Petroleum Act 2006*
OPGGSA	*Offshore Petroleum and Greenhouse Gas Storage Act 2006*
OPMP	Operational Pipeline Management Plan
OSH	Occupational Safety and Health (WA)
OSHA	Occupational Safety and Health Administration (United States)
PC	Productivity Commission
PHMSA	Pipeline and Hazardous Materials Safety Authority (US)
PIMS	Pipeline Integrity Management System
PIRSA	Department of Primary Industries and Resources of South Australia

PL	Pipeline Licence
PLAR	*Petroleum Legislation Amendment and Repeal Act 2005*
PMP	Pipeline Management Plan
PRS	Production reporting system
PSA	Petroleum Safety Authority (Norway)
PSLA	Commonwealth *Petroleum (Submerged Lands) Act 1967*
PSMP	Pipeline Safety Management Plan
QRA	Quantitative risk assessment
RED	Resources and Environment Division (WA)
RET	Department of Resources, Energy and Tourism (Commonwealth)
ROV	Remotely operated vehicle
RSD	Resources Safety Division (WA)
SARPS	Standards and recommended practices
SC	Safety Case
SCC	Stress corrosion cracking
SCIs	Safety Critical Items
SGE	Sales Gas Export (pipeline on Varanus Island)
SGL	Sales Gas Line (pipeline on Varanus Island)
SHD	Safety and Health Division (WA)
SHED	Safety, Health and Environment Division (WA)
SLAs	Service level agreements
SMS	Safety Management System
SODM	State Supervision of Mines (Netherlands)
SSS/ROV/Diver	Side Scan Soner/Remotely Operated Vehicle/Diver
TPL	Territorial Sea Pipeline Licence
TSB	Transportation Safety Board of Canada
TSI Act	Commonwealth *Transport Safety Investigation Act 2003*
UT	Ultrasonic testing
VI	Varanus Island
WA MOSOF	Western Australian *Management of Safety on Offshore Facilities Regulations 2007*
WA PGERA	Western *Australian Petroleum and Geothermal Energy Resources Act 1967* (WA)
WA PPA	Western Australian *Petroleum Pipelines Act 1969*
WA PSLA	Western Australian *Petroleum (Submerged Lands) Act 1982*
WEL	Woodside Energy Limited
WRMC	Workplace Relations Ministers' Council

Terms of reference

Background

The Minister for Mines and Petroleum has decided that he will continue the Department's investigation into the incident that occurred on 3 June 2008 on Varanus Island (the Incident).

The original investigation:

- was requested by the then Department of Industry and Resources (DoIR) as the regulator;
- was initiated by the Director Petroleum and Royalties Division on 4 June 2008;
- was to address: the pertinent sequence of events on Varanus Island during the Incident: the likely cause(s) of the Incident; any actions and omissions by the operator of the Varanus Island facility, or its contractors, leading up to the Incident and during the Incident that may have contributed to the cause of the Incident; and the identification of any potential for injury to persons arising directly from the fire and explosion(s) at the time of the incident.
- was undertaken by both the National Offshore Petroleum Safety Authority (NOPSA) and DOIR officers; and
- had a deliverable of providing a report to the Director, Petroleum and Royalties Division.

The investigation team delivered what was termed the *Final Report of the findings of the Investigation into the Pipe Rupture and Fire Incident on 3 June 2008 at the Facilities Operated by Apache Energy Ltd on Varanus Island* (Initial Report) on 7 October 2008, but the findings in that report were limited because of the timeframe for the report and the unavailability of critical evidence at the time of the issue of the report. The Initial Report notes that *'Delays were experienced in accessing the reports arising from the examination and testing of the pipeline samples removed from the incident site.'* and *'These matters directly impacted on the ability of the investigation team to develop its findings within the agreed time period and resulted in aspects of some lines of the investigation not being fully settled.'*

The pipeline test reports referred to above are those commonly described as 'the PearlStreet reports', on non destructive and destructive testing of the pipe which exploded. An analysis of the data in 'the PearlStreet reports' is essential for understanding the likely cause of the incident. The Initial Report also noted a gap in *'Identification of specific technical details relating to the cathodic protection of the 12" sales gas pipeline'*.

Apache itself in response to the Initial Report was critical of the investigation not establishing why the corrosion coating had failed and in what timescale, and argued the need for a more considered investigation report after all metallurgical testing results were available.

As both of the PearlStreet reports are now available, DMP will continue its original investigation into the incident, with a view to being able to make significantly improved findings to the Executive Director, Petroleum and Environment Division, and consequently to the WA Minister for Mines and Petroleum. This investigation will be termed the Final Phase of the Investigation into Pipeline Rupture and Fire on Varanus Island.

DMP does not have available staff with the expertise required to perform the continued investigation. At the time of the initial investigation, NOPSA provided staff with this expertise, but NOPSA withdrew from the service contract between NOPSA and DMP earlier this year.

In order to expedite access to information and to Varanus Island, if necessary, relevant members of the Investigation Team will be appointed as Inspector(s) under the *Petroleum Pipelines Act 1969* ('the Act'). Expertise in petroleum Occupational Health and Safety (OHS) and in major accident and incident investigation is essential and knowledge of the Varanus Island incident is highly desirable. Given the timescale, DMP proposes to obtain services from Mr Kym Bills, Executive Director of the Australian Transport Safety Bureau and Mr David Agostini, a senior oil and gas industry expert, who will manage the investigation assisted by consultants to the DMP including other technical and subject experts.

Purpose

The purpose of the investigation is to:

1. Continue the investigation that was initiated by the then Director, Petroleum and Royalties Division of DOIR on 4 June 2008.
2. Identify the facts and events relevant to the Incident.
3. Identify the likely cause(s) of the Incident.
4. Identify any necessary or desirable licence conditions made under the Act having regard to legal advice and direction provided by DMP.

Scope

The investigation will address:

1. The pertinent sequence of events on Varanus Island during the Incident.
2. The likely cause(s) of the Incident.
3. Any actions and omissions by the operator of the Varanus Island facility, or its contractors, leading up to the Incident and during the Incident that may have contributed to the cause of the Incident.
4. The identification of any potential for injury to persons arising directly from the fire and explosion(s) at the time of the incident.
5. Any issues with respect to regulation under the Act.

The investigation will be conducted in the context of, and will have regard to, good industry practice, the commitments made by the operator in respect of its operation of the Varanus Island facilities and in the context of the Act and regulations made under the Act and licence requirements imposed under the Act.

The following additional tasks are required:

- Assess the adequacy of the Act and regulations made under the Act, having regard to their interaction with other legislation, in regulating the construction, operation and maintenance of pipelines for the conveyance of petroleum and purposes connected therewith, including but not limited to occupational health and safety issues related to such pipelines and integrity of pipelines, with a focus on the Incident at Varanus Island.
- Assess the adequacy of the Varanus Island Safety Case, required by licence conditions imposed under the Act, for the construction, operation and maintenance of pipelines, especially the integrity of high pressure pipelines crossing the beach and recommending improvements to the Safety Case.
- Recommend improvements to the Act and regulations made under the Act, having regard to their interaction with other legislation.
- Recommend improvements to the processes used by those administering the Act to meet their regulatory obligations.

The scope of the Investigation Team will include but not be limited to:

- reviewing the Initial Report prepared by the previous investigation team;
- reviewing the PearlStreet reports and expert analysis of the data;

- reviewing the cathodic protection systems for the incident pipelines;
- reviewing Apache's internal root cause analysis of the incident;
- conducting any necessary interviews with relevant people;
- considering any relevant operator organisational and human factors;
- reviewing other relevant available information;
- highlighting any broader safety issues and lessons for the future; and
- the preparation of a Final Investigation Report.

The draft Final Investigation Report will be completed by Wednesday 10 June 2009, or otherwise as mutually agreed by DMP and the Investigation Team and dependent on Apache Energy providing necessary information in a timely manner. A final report will be provided to the Minister of Mines and Petroleum by 30 June 2009.

DMP obligations

DMP will provide executive secretariat support for the Investigation.

Given the extraordinary legal circumstances surrounding the investigation, DMP will indemnify, hold harmless and defend each member of the Investigation Team ('the Member') in relation to any loss or liability arising as a consequence of any claim by a third party against the member in connection with the conduct of the Investigation provided that each member so indemnified acts in good faith; within the scope of the member's duties under these Terms of Reference.

Executive summary

In the early afternoon of 3 June 2008 a high pressure 12 inch export sales gas pipeline (SGL), critically weakened by a region of external corrosion, ruptured and exploded on the beach of Varanus Island off the coast of Western Australia. Almost immediately, a parallel 12 inch high pressure inflow gas pipeline less than a foot away also ruptured. Both pipelines directed intense fires towards the main gas processing plant on the island and nearly an hour later two other pipelines, the 16 inch sales gas pipeline and a 6 inch import gas line, ruptured closer to the plant. Fire and heat caused two further 4 inch pipelines to rupture. Large rocks and debris from the explosions penetrated about 50 metres into the Harriet Joint Venture gas plant. There was approximately A$60 million in damage to the plant. Plant closure led to up to A$3 billion of losses to the WA economy which lost 30 per cent of its gas supply for two months. By early October 2008 production from Varanus Island was up to around two thirds of previous production, however full restoration was still not achieved more than a year later.

In a complex, high hazard industry such as offshore oil and gas, society expects a robust regulatory regime in which operators maintain safety to minimise the risk of a major accident event and regulators provide assurance that this is being done. The duty of care/safety case co-regulatory regime progressively introduced in Australian waters since 1992 places the onus on operators and provides them with flexibility in how best to manage hazards and minimise risk. But regulatory competence, clarity and scope covering all relevant offshore operations is a fundamental requirement of the regime. However, on Varanus Island itself a full safety case regime was not yet required under Western Australian law per se but only as a PPA licence condition (PL12 licence).

Australia's offshore industry has a good safety reputation. However, in recent years a number of key safety indicators have plateaued or worsened. In Australia, as overseas, not all operators have a mature safety culture or seek to operate at best practice safety levels. Regulators must deal with differences in motivation and culture among operators by targeting scarce regulatory resources towards higher risk operators, facilities and activities. Better practice co-regulatory regimes require balance and integration between prescriptive elements and cooperative elements and genuine dialogue, goodwill and pro-activity among participants.

Apache, a fully owned subsidiary of the US company Apache Corporation, was the operator on Varanus Island and the majority shareholder in both joint ventures on the island. Because the onus for safety was with the operator, Apache Northwest Pty Ltd, we have not considered any role by the minority joint venture partners. We found that there was a range of Apache documentation that should have alerted the operator to serious risks involving external corrosion around the shore crossing of the 12 inch SGL, where it ruptured. We believe that the risk of this occurring was not only foreseeable but to some extent foreseen. Some Apache consultant reports seemed to understate the risks involved, perhaps because they had not reviewed prior consultancy reports which had already identified corrosion vulnerabilities. Hazard mitigation measures proposed in the safety case and Pipeline Safety Management Plan for the Varanus Island hub pipelines were inadequate and did not properly assess risks inherent in the pipeline system on the island, especially in the vicinity of shore crossings. Overall, the lack of robust corrosion data and prevention systems for the Varanus Island shore crossing zone of the 12 inch SGL was not addressed prior to the explosion.

While the hazard and risk of a major accident event from possible external corrosion was clear in Apache's documentation, Apache's understanding of the cathodic protection system on the 12 inch SGL was confused and confusing. Worryingly, this seems to be so even in relation to the CP system that was put in place after the incident raising the possibility of a further incident. Professor Rolf Gubner has outlined four scenarios for the external corrosion based on well-known industry mechanisms. These include a pipeline anti-corrosion coating failure due to: lack of adhesion during application shielding the pipe from CP protection, interference from direct current from adjacent pipes with different potentials, interference from alternating current from other structures, and disbondment due to CP over-protection. Irrespective of the mechanism, Professor Gubner expects that corrosion would have progressed at no more than about 2 mm a year so that the thinning of the 12 inch SGL to the point of rupture would have taken in the order of five years. Annex 11 includes some even more rapid examples.

High reliability organisations (HROs) operate in environments where it is not prudent to adopt a strategy of learning by mistakes and this is particularly relevant to a major accident event (MEA) in the offshore industry. HROs deploy sufficient people in the normal course of events to be able to deal with abnormal situations when they arise. Apache's strategy to operate with low manning levels, as identified in the Lloyd's Register report, leads to vulnerability in the event of abnormal operations.

We also examined Apache's safety culture and found that it was probably best seen as in the middle rank within some well-known hierarchies and was generally not at the level of being proactive or generative. Organisations with conventional outlooks and cultures tend to focus on successes rather than being ever mindful of failure. When accidents occur, they see them as 'fundamentally surprising' events because they call into question the organisation's model of the risk they face and the effectiveness of countermeasures employed. NASA's adoption of a policy of 'better, faster, cheaper' prior to the space shuttle accidents may have parallels with Apache's focus on cost and 'a sense of urgency' and suggest that Apache needs to better consider human and organisational factors and 'resilience engineering'.

While the primary technical and operational failings involved the operator, our examination of the 3 June 2008 incident also included consideration of the regulatory regime. We encountered a confusing mishmash of jurisdictional, legal, process and regulatory interfaces upon which was overlaid poor relationships among regulators. In such an environment, even serious operator shortcomings were far less likely to be found and addressed to reduce the risk of a major accident event.

On 3 June 2008, the Varanus Island plant, including the area in which all four pipelines ruptured, was regulated by the WA Department of Industry and Resources (DOIR) and defined as a 'pipeline' under the WA *Petroleum Pipelines Act 1969*. Under this Act, the increasingly complex Varanus Island hub activities were licensed under pipeline licence PL12 which has gone through 17 variations since it was granted in 1985, most of which had occurred since Apache took over in 1995. One variation in 1998 introduced a 'safety case' requirement but this was grafted into a prescriptive licensing regime which had poor and inadequate compliance penalties.

From its creation on 1 January 2005, the National Offshore Petroleum Safety Authority (NOPSA) provided contracted regulatory services to DOIR with respect to Varanus Island. In contrast, oil and gas feeding into the Varanus Island plant from facilities in Commonwealth waters had been covered by a comprehensive duty of care/safety case regime under Commonwealth law since at least 1996. From 27 March 2007 WA amended its *Petroleum (Submerged Lands) Act 1982* and regulations to mirror a safety case type regime with a requirement for Pipeline Management Plans in WA State waters. NOPSA had conferred power to consider the safety element of these by 27 March 2008.

The Safety Division in the WA Department of Consumer and Employment Protection (DOCEP) was the OHS regulator for the onshore petroleum and mining industries. From 2005, it provided (unpaid) regulatory advisory services to the offshore regulator in DOIR that were ultimately formalised in a MOU in late 2007. These services included the mainland end of the 12 inch SGL from the low water mark to the compressor station and main pipeline to Perth over 30 km away. While seriously under-resourced, from late 2006 DOCEP proactively drew Apache's attention to the lack of pipeline integrity data including for the condition and safety of the 12 and 16 inch sales gas lines. Not satisfied with Apache's response, in April 2007 DOCEP formally suggested that DOIR write a tough regulatory letter to Apache that included consideration of in-line-inspection for corrosion (intelligent pigging).

The DOIR regulator did not send the letter drafted by DOCEP but sent an amended and less demanding version. When an Apache PMP that included the entire 12 inch SGL was received by DOIR in March 2008, DOCEP's advice on it was not sought before it was approved. DOCEP considered that its advice was treated by DOIR as coming from a contractor and could be accepted or rejected. In hindsight it is clear that DOCEP was correct in its assessment of the risks of the 12 inch SGL.

Under the PL12 licence, the Petroleum and Royalties Division in the Department of Industry and Resources (DOIR) was the regulator of the Varanus Island facilities including the sections of the four main pipelines that ruptured. While most of the Varanus Island plant is licensed as a 'pipeline', the 12 inch high pressure gas import pipeline next to the 12 inch SGL, that ruptured first, was not declared to be a pipeline or licensed by DOIR. Although DOIR retained regulatory responsibility, in 2005 half of its technical safety staff were recruited by the new NOPSA and almost all of the rest went to DOCEP and to industry. DOIR either did not place adequate priority on replacing such expertise or was unable to replace them because of market conditions. The Petroleum and Royalties Division in DOIR also faced a large range of other policy and regulatory responsibilities including responsibility for resource management (exploration and development approvals) that overwhelmed the division resources and further reduced its focus on safety.

DOIR audits of Apache prior to the creation of NOPSA uncovered some serious issues including with change management, maintenance and audit systems. In 2001, a lack of specialist corrosion staffing was linked to a case of dangerous external corrosion in offshore platform pipework that was only discovered by chance. In addition to many positive findings, NOPSA's audits also found deficient systems and maintenance issues. From 2005 the DOIR regulator received audit and other reports and advice from DOCEP and NOPSA but, with the one exception noted above, it took no independent initiative to seek remedy to identified shortcomings.

In mid 2006 just before the 21 year renewal of the PL12 licence was due, DOIR decided to accept a validation exercise by Lloyd's Register which had been engaged by Apache, for the purpose of supporting a licence renewal. DOIR's safety regulatory attention was cursory and it wrote to NOPSA seeking advice on whether Apache's provision of what amounted to Lloyd's proposed scope for future validation work, was itself sufficient to enable DOIR to renew the PL12 licence for 21 years. NOPSA appropriately advised that the validation work needed to be done. DOIR did not consult NOPSA further on the matter.

DOIR states that on the basis of only a one page executive summary to the final Lloyd's 16-page validation summary report in May 2007 it was supportive of a 21 year licence renewal. Subsequent to the accident, Apache referred to this page as an indication of Lloyd's support for the integrity of the pipeline system. We agree that this page and the similar concluding page give an overly positive assessment but note that a reading of the detail, including in the other 14 pages, places the proposed renewal in perspective. Two recommendations by Lloyd's Register were stated to be 'required to be implemented' to avoid DOIR cancelling the PL12 licence and 'numerous' suggestions were made to help Apache attain 'best practice'. The detailed background was in earlier Lloyd's Register reports that DOIR did not receive or seek.

Using Commonwealth safety case regulatory and guidance material to form a template, the DOIR regulator had accepted a safety case for the Varanus Island hub on 22 July 2002 including the Sales Gas Pipelines. During our investigation, documentation was difficult to access and DOIR agreed that its files were often extremely poor. Systems to monitor or follow up licence conditions were incomplete and it was not clear how conditions added during licence revisions applied to pre-existing plant and pipelines. Apache's 2007 revision of the safety case for the Varanus Island hub included as a major accident hazard the possibility of external corrosion causing a pipeline rupture and jet fire escalating to a major accident event (MAE) with multiple lives lost. We found no evidence that DOIR undertook analysis itself or that particular advice was sought from NOPSA or DOCEP on hazards and MAEs and their mitigation. The same was true a few months later with respect to the Varanus Island hub Pipeline Management Plan (including the ruptured pipeline areas) and its safety elements at shore crossings and onshore.

Overall, DOIR was an under-resourced and less than competent safety regulator working in a difficult legislative and industry environment in which safety case language was confusingly grafted into an already inadequate licensing regime. We do not believe DOIR regulation met any of the nine principles of offshore regulation agreed in 2002 by the Ministerial Council on Mineral and Petroleum Resources (MCMPR). It unconsciously hindered robust regulation of Varanus Island: there was minimal oversight and poor use of contracts and MOUs with NOPSA and DOCEP, and personal relationships were unhealthy and detrimental to safety.

NOPSA provided audit services to DOIR on Varanus Island in relation to later versions of the 2002 safety case from 2005 until a five-yearly safety case revision was due in mid 2007. DOIR was the Varanus Island regulator and its lack of engagement after NOPSA submitted reports and advice, and the weaknesses in the WA legislation and PL12 licence, no doubt constrained NOPSA's pro-activity. However, we believe that NOPSA could, for example, have recommended enforcement action when serious deficiencies were found or were not addressed in a timely way.

On 31 October 2007, NOPSA accepted the revised Apache Hub Safety Case in relation to NOPSA's legislated offshore responsibilities and on 6 December 2007 DOIR accepted the safety case in relation to its responsibilities including 'production facilities located on Varanus Island'. It did this late - NOPSA had advised DOIR on 31 October that the onshore island elements of the safety case were satisfactory and recommended DOIR acceptance but DOIR had to be reminded through follow-up correspondence.

With regard to the 2007 Varanus Island Hub Safety Case and the March 2008 Apache Pipeline Management Plan, NOPSA accepted the portions for which it had legislated responsibility only, but the DOIR regulator considered that NOPSA had endorsed the broader details. Regarding the Pipeline Safety Management Plan (PSMP) NOPSA wrote to DOIR citing the regulations under which it provided acceptance 'in full'. A close look at the cited legislation would show that these did not include the portions of the pipelines above the low water mark on Varanus Island. However, the document included the portions on the island and NOPSA's letter included more general statements about the whole PSMP covering the health or safety of persons at or near the pipeline.

The NOPSA services contract with DOIR stated that NOPSA 'will be responsible to the project manager' in DOIR for the duration of the contract and 'will provide advice and contractor services for the contract areas' including with respect to 'evaluation of safety case submissions' and 'recommendation to DOIR of acceptance' and 'review of safety aspects of Pipeline Management Plans'. NOPSA was paid a $10,000 monthly fee for these services. The contract was silent on whether NOPSA had to be asked first. NOPSA submitted that it should have been asked but we note that it did not require to be asked in certain contracted areas such audits and inspections. Clearly, the jurisdictional complexity and complex interfaces in this case clouded the critical issues and militated against effective safety regulation. Given the ambiguities and tensions surrounding service contracts, we do not support future contract arrangements for regulatory services but rather a clear conferral of powers from WA to NOPSA with respect to Varanus Island and like facilities.

The legislative environment in WA was a contributing factor to regulatory ineffectiveness and needs to be simplified as soon as possible. We believe it is inappropriate to use a pipeline licence under the *Petroleum Pipelines Act 1969* to regulate Varanus Island, particularly given the shortcomings of that legislation with respect to safety cases and penalties. In our assessment, conferral of powers to NOPSA to maximise integration of offshore petroleum safety and integrity regulation and a properly resourced regulator in an augmented safety case regime is the best option for future safety.

We also strongly recommend the creation of a properly resourced national independent no-blame offshore oil and gas and petroleum pipeline investigation capacity that can investigate major accident events and near misses in the future with appropriate powers so that learning important safety lessons is not made hostage to legal action.

Recommendations

Recommendations

R 1 We recommend that Western Australia seeks the establishment of a properly resourced independent national safety investigation body to investigate serious offshore oil and gas and onshore petroleum pipeline accidents and incidents. The body should be empowered to compel documents and witnesses and be required to make public a professional systemic no-blame investigation report that is appropriately protected from legal action for the purpose of improving future safety. (p 64)

R 2 We recommend that DMP ensure that there is clarity in its regulation of safety across oil and gas and other high hazard industries in terms of which standards are required to be applied under licences, regulation and legislation and that there is an obligation upon operators to apply the most appropriate standard to reduce risk to ALARP in accordance with good industry practice. (p 66)

R 3 We recommend that WA ensure, as a matter of urgency, that all of its legislation and regulation mirrors Commonwealth offshore legislation and regulation and enables and facilitates the exchange of safety information between jurisdictions. In the interim, WA should seek to amend existing licence and safety case requirements to facilitate exchange of safety material. (p 100)

R 4 We recommend that where it has regulatory responsibility, DMP develop and maintain a database of licence conditions and actively monitor compliance of those conditions. Licences should be updated to remove outdated conditions and clarify remaining applicability and any agreement to remove requirements should be documented. (p 102)

R 5 We recommend that pipeline licences should be used for significant pipelines and not major offshore facilities like Varanus Island. (p 102)

R 6 We recommend that if a validation report has been required to support a regulatory approval, the regulator should ensure that the complete report is received and considered as part of the approval process. The regulator should also be able to speak directly to the validation team to discussion further any issues raised within the report. This may require amendment to legislation to ensure that the regulator can engage in confidential discussions with the validator without the operator present. (p 104)

R 7	We recommend that WA support a full duty of care/safety case co-regulatory regime for offshore oil and gas across Commonwealth and State coastal and internal waters which minimises jurisdictional and regulatory interfaces and ensures that a competent regulator is appropriately resourced. (p 105)
R 8	We recommend that DMP develop a robust risk assessment matrix for use in assessing and responding to the safety culture, motivation, capacity and changing risk associated with each oil and gas and major hazard operator and facility. (p 118)
R 9	We recommend that WA confer powers to enable NOPSA to regulate all offshore safety and integrity including all facilities and pipelines in the water and the WA islands (including Varanus Island) which export gas by pipeline. NOPSA's authority should extend to the nearest valve on the mainland above the shore crossing or other logical system boundary. (p 119)
R 10	We recommend that following a decision to confer power to NOPSA that includes Varanus Island, WA seek a mechanism for the Commonwealth to enable NOPSA to provide short-term regulatory services pending the conferral. This may involve the appointment of NOPSA officers and supervisors as inspectors under WA legislation. (p 119)
R 11	We recommend that the potential for conflict between safety outcomes and environmental outcomes be recognised and openly considered as part of project approvals. Moreover it is important that a holistic view is taken of major facility hubs as new developments are added to ensure risks are not being added that are unidentified and not managed. This is an issue which would benefit from further, targeted research. (p 121)
R 12	We recommend that DMP review and seek to minimise potential conflicts of interest with respect to the offshore industry of its administrative arrangements, delegations and functions for policy, resource management, environmental regulation, safety regulation and safety investigation. (p 122)
R 13	We recommend that as a condition of PL12 licence renewal WA require a full assessment of corrosion protection systems on Varanus Island, including the technical design and operation of cathodic protection at shore crossings with multiple pipelines and possible interference and stray current effects. (p 139)
R 14	We recommend that Western Australia facilitate establishment of a formal technical committee which brings together corrosion expertise from industry, professional associations, regulators and academia with the purpose of promoting best practice in asset integrity assurance. We also support the establishment of a certification system for personnel carrying out cathodic protection services, along the lines of the European or US (NACE) models. (p 139)

Introduction

The Western Australian offshore oil and gas industry

While small by international standards, Australia's upstream oil and gas industry is an important contributor to the Australian economy, adding $15.3 billion (approximately 2 per cent) to GDP and accounting for $5.5 billion in tax revenue in 2004–05. While a net importer of oil, Australia is a significant exporter of gas, with exports of LNG worth $5.2 billion and LPG worth $1 billion in 2006–07. Because of the high cost of entry, the sector is dominated by large multinationals. Companies operating in the Australian offshore waters enjoy a low level of sovereign risk and the 15,000 employed by the sector enjoy relatively high wages and a safe working environment under State/Territory and Commonwealth legislation. The lion's share of the industry is based in Western Australia, which accounts for 71 per cent of Australia's gas production and 66 per cent of its oil and condensate production. Petroleum exploration in Western Australia and its adjacent Commonwealth waters were worth $799 million in the first quarter of 2009.[1]

Australia's gas production is sold through long term contracts mostly for export but some, such as part of the gas production from the Woodside-operated North West Shelf Venture and the Apache-operated Varanus Island hub, is destined for domestic use in Western Australia. Of more than 29,000 kilometres of pipeline in Australia, over 21,000 kilometres is used to transport natural gas, of which 5,700 kilometres is in Western Australia.[2] On an incident per 1000 km basis, major pipeline incidents are rare in Australia and, overall, Australian pipelines appear to be well managed. A 2004 study found that Australian pipelines have a much better safety record than Europe and the US and commends the safety performance of the Australian pipeline industry.[3]

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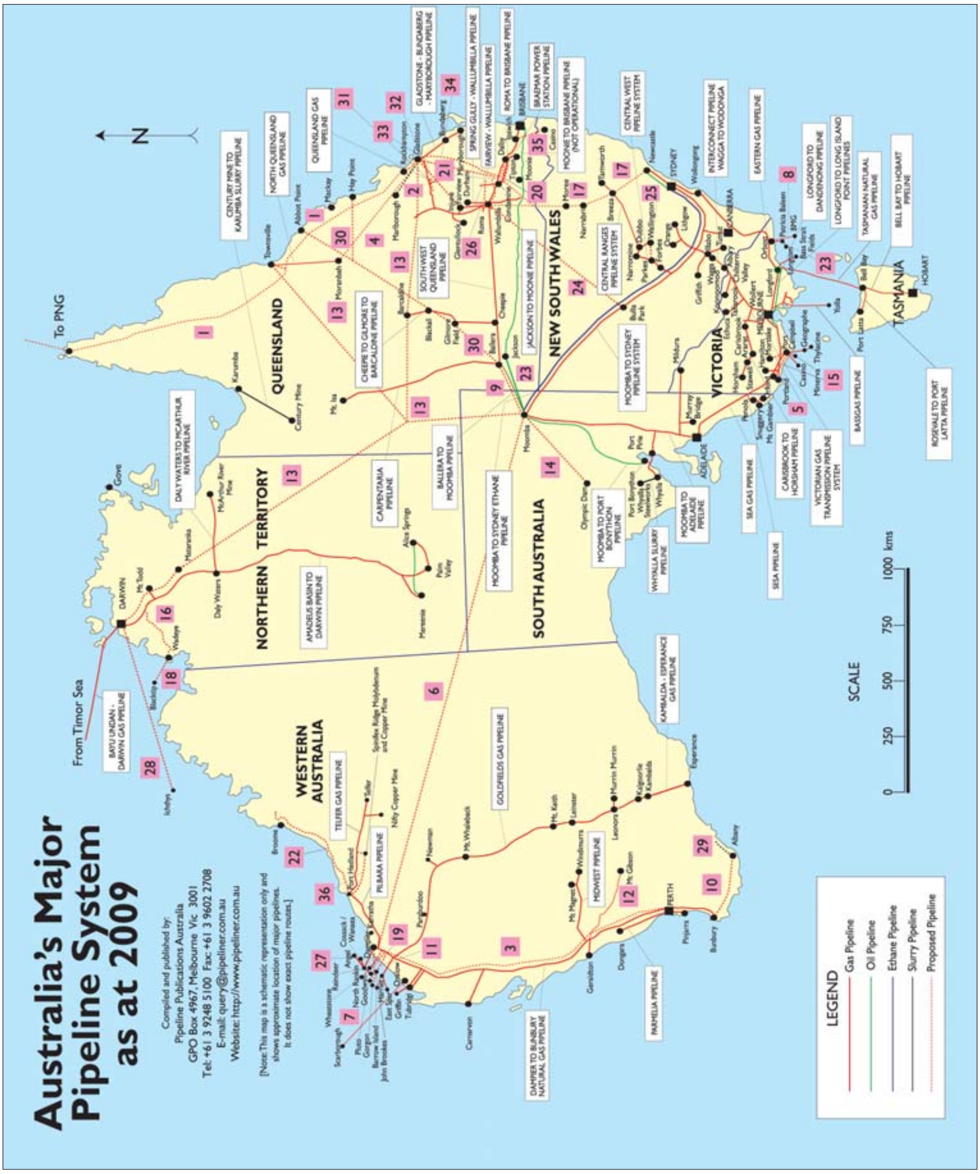
1 WA Department of Mines and Petroleum, *Petroleum in Western Australia 2009*, April 2009.

2 <www.apia.net.au/industry/facts-and-figures.cfm> accessed on 9 May 2009.

3 Peter Tuft and Craig Bonar, *Review of Pipeline Incident Data to 2004*.

Figure 1: Australia's major pipeline system



Varanus Island

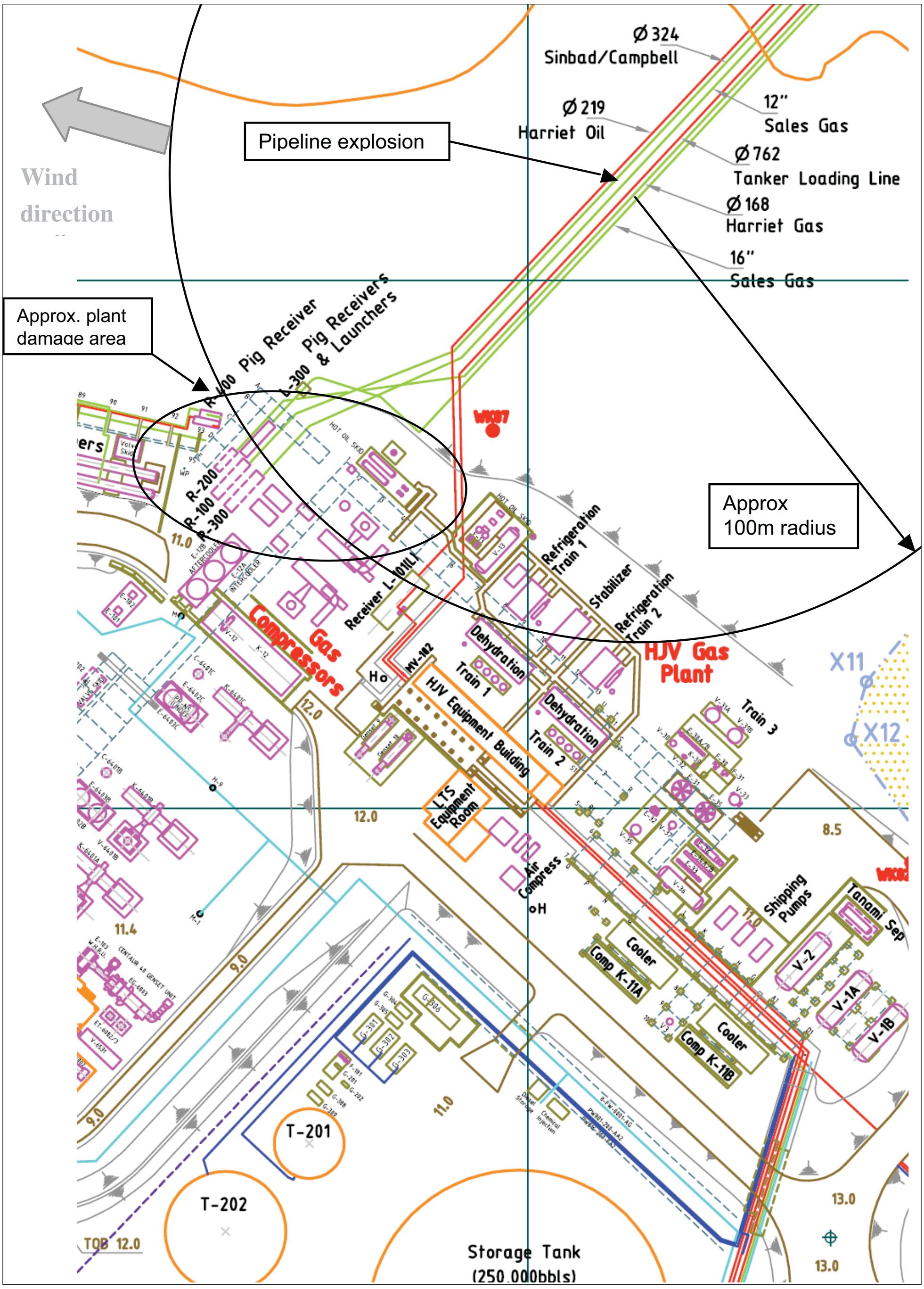
Varanus Island lies off the coast of Western Australia about 100 km west of Karratha. The island is the site of a hub processing oil and gas, imported via subsea pipelines, from production wells in the vicinity. Crude oil is exported from the island by a pipeline to a tanker vessel berth while sales gas is exported to the mainland by a 12 inch and a 16 inch subsea gas pipeline. The sales pipelines connect with the on-shore Dampier to Bunbury Natural Gas Pipeline (DBNGP) and Goldfields Gas Transmission pipeline.

Apache operates the Varanus Island oil and gas processing and distribution on behalf of other joint venture owners. Joint facilities are also operated on the island under a cost-sharing agreement between joint ventures.

The first joint venture based on Varanus Island was the Harriet Joint Venture (HJV). Apache entered the venture in January 1995, and has operated the joint venture since then. Apache owned 68.5 per cent of HJV at the time of the Varanus Island incident. The other owners of the HJV are Tap (Harriet) Pty Ltd and Kufpec Australia Pty Ltd. The HJV is based on offshore platforms to the northeast of Varanus Island that provide oil, gas and condensate to the island through a pipeline corridor to the northeast of the island. Gas is processed on the island and is then exported to the mainland through the 12 inch SGL that leaves the island through the same pipeline corridor. This is the pipeline that ruptured first.

The East Spar Joint Venture (ESJV) started production in 1996. Apache operates the joint venture and owns 55 per cent of ESJV at the time of writing the report, the other partner being Santos (BOL) Pty Ltd. The joint venture is based on offshore facilities to the west of Varanus Island. The joint venture ceased production in 2006. Production facilities from the ESJV are presently being used for gas from the John Brookes Joint Venture to the northwest of Varanus Island which is operated by Apache with 55 per cent ownership. The other owner of the John Brookes Joint Venture is Santos (BOL) Pty Ltd with 45 per cent. The joint venture started production in 2005 and, at the time of writing this report, was producing approximately double the quantity of gas as the HJV. A separate pipeline transfers the gas to Varanus Island. After the gas has been processed, it is normally exported to the mainland through the 16 inch SGL which occupies the northeast pipeline corridor.

Figure 2: Location of explosion on beach



The Varanus Island incident

At around 1330 on 3 June 2008 the 12 inch sales gas line (SGL) from Varanus Island to the mainland ruptured at the beach crossing and the released gas exploded into flame. The rupture of the 12 inch SGL caused the near simultaneous failure of the adjacent 12 inch import gas line from the Campbell and Sinbad offshore facilities located northeast of Varanus Island. The explosions created an 8 m x 30 m crater on the beach to a depth of about 2 m, exposing the buried pipelines and showered the NNE section of the plant with limestone rocks, stones and pieces of concrete weight coating from the ruptured pipelines[4].

The Island control room operators immediately initiated the 'Emergency Shut Down' procedure and plant 'blow-down' was started. By 1350, all 150 personnel on the island had mustered safely with no injuries sustained[5]. The emergency response team assessed the situation and deployed three water monitors to cool the plant adjacent to the area of the fire. The control room staff initiated procedures to reduce pressure in both the ruptured 12 inch SGL and the 16 inch SGL as a precautionary measure.

The two crude oil pipelines remained intact. However, almost an hour after the initial rupture and fire, the 16 inch SGL and the 6 inch gas import line ruptured closer to the Harriet Joint Venture (HJV) plant and also caught fire. Further action to isolate critical infrastructure continued throughout the afternoon and, as a precaution, staff on the offshore Apache structures were brought to the island. By 1550, the isolations were complete, including isolating the 16 inch and 12 inch export lines from the Dampier-Bunbury Natural Gas Pipeline (DBNGP). A 4 inch Agincourt gas lift pipe located at the edge of the plant in an overhead rack and a 4 inch condensate line pipe 25 metres in to the plant also ruptured and fed the fire which directly destroyed structures 50 metres into the plant[6]. At 1710 evacuation of all non-essential island personnel began. A monitoring crew of 14 remained overnight. By 0700 on 4 June the fire had been extinguished. The flying rocks and debris, and the intensifying fires had the potential to injure or fatally injure personnel, particularly if the prevailing wind had been onshore toward the HJV plant.

Prior to the pipeline rupture and explosions on Varanus Island on 3 June 2008, the Apache operated facilities contributed approximately 30 per cent or 350 terajoules (TJ) per day to the Western Australian

4 The largest rock fragment found within the confines of the plant weighed 17.5kg.

5 This conformed to the 20 minute muster standard in the revised 2007 Varanus Island Hub Safety Case rather than the 10 minute standard in the original 2002 Varanus Island hub safety case.

6 ALERT/Burgoynes report produced for Apache, 16 September 2008.

gas supply via the DBNGP and the Goldfields Gas Pipeline. Supply was partially restored in August 2008 to 120 TJ and, as at May 2009, was at just under
300 TJ per day. Woodside Energy Ltd has partially offset the lost supply by increasing supply from its North West Shelf joint venture. Apache gas is used for a mix of electricity generation, and industrial and residential supply and over 560,000 residential and small businesses were affected by the Varanus Island incident.[7]

It is reportedly costing Apache around A$60 million to repair the pipelines and plant, and the company and its joint venture partners have had to deal with the loss and delay in revenue stream. In addition, the pipeline failure had a major impact on the Western Australian economy, estimated by the Western Australian treasury as being in the region of A$2.6 billion with other estimates around $3 billion. At the time of writing, the Varanus Island facilities are still not fully operational 12 months after the incident.

Varanus Island incident investigations

After the explosion two NOPSA inspectors and one DOIR inspector travelled to Varanus Island and documented the details of the ruptures, explosions, fires and damage. The investigation continued in Perth with the main NOPSA team comprising four inspectors and a team leader with oversight by the Deputy CEO and CEO and the main DOIR team comprising two inspectors and an administrative officer with oversight from a branch head and the Director of the Petroleum Division[8]. The final report dated 7 October 2008 was largely the work of NOPSA under its contract with DOIR to provide technical services.

Given the tight timescale in which it was written, the issues noted with operator cooperation, and its constrained terms of reference, we believe that the 7 October 2008 report (Annex 1) formed a creditable basis for a future prosecution and for a future safety investigation.

However, it is not without weaknesses.[9] In announcing the final phase to this investigation on 8 May 2009, the Western Australian Minister for Mines and Petroleum, the Hon Norman Moore MLC noted that the 7 October 2008 report was unavoidably limited by its reporting timeframe and the absence of critical evidence, including results from testing of the pipeline which had since become available. Previous

7 Senate Standing Committee on Economics, *Inquiry into matters relating to the gas explosion at Varanus Island, Western Australia*, December 2008.

8 The level of oversight and meetings between senior officials within NOPSA and DOIR diminished as the investigation proceeded over some weeks.

9 See Annex 2

statements by the Minister and Premier had referred to the need to assess any deficiencies in the regulatory regime.

The purpose of this report is to address these and other outstanding issues from the initial report. Under the terms of reference we have been given, we are also asked to look at the regulatory environment covering the Varanus Island Hub and to consider wider human and organisational factors which might have contributed to the cause of the incident. This should enable the incident to be understood in a systemic manner and provide lessons learned for future regulation and licensing which may have broader relevance for the offshore petroleum industry in Australia and the world.

Immediately following the 3 June 2008 incident, Apache contracted two consultants who at short notice flew to Varanus Island from Singapore and extensively documented the incident. There was some extra detail contained in their report dated 16 September 2008 compared with the DOIR/NOPSA 7 October report, including the rupture of the 4 inch Agincourt and 4 inch condensate pipes and on the extent of fire damage approximately 50 metres into the Harriet Joint Venture plant and the location and impact of rocks and other material from the explosions[10].

Following the release of the DOIR/NOPSA report, a small team of officers within DOIR (DMP from 1 January 2009) progressed investigatory work towards a possible prosecution in relation to the incident. This included requiring copies of relevant documents from Apache and progressing metallurgical testing jointly with Apache through the PearlStreet facilities in Perth (the documentation of this is too voluminous to annex). DOIR/DMP also obtained reports on the pipe metallurgy from an expert (see Townend Report, Annex 3) and on corrosion from another expert (see Martin Report, Annex 4). Such a prosecution had to be initiated within 12 months of the incident on 3 June. This timescale was met with a prosecution initiated on 27 May 2009.

Apache has repeatedly stated that it is separately working on a comprehensive investigation into the root cause of the incident. Such an investigation would, if completed in a thorough manner, be in accordance with industry best practice so that safety lessons could be learned for the future. However, while in the first quarter of 2009 Apache stated that this report was due to be completed 'soon', it had still not been completed 12 months after the incident. Moreover, when in late May 2009 we formally, under section 63 of the PPA, compelled any drafts of the report to be produced, Apache responded that it held no such documents and referred to this work being done

10 ALERT/Burgoynes report produced for Apache, 16 September 2008.

by an unidentified third party[11]. Subsequently, when we formally sought to compel a copy of the service contract and emails between Apache and the third party, Apache responded on 5 June that it did not accept it was a proper request relating to a pipeline and in any event said it did not have such documents in its custody.

We regard it as totally unsatisfactory that safety material relating to a major petroleum pipeline incident on Varanus Island is not made available by the operator to the regulator and, through our investigation under the PPA, to the Minister. Our investigation under the terms of reference at the beginning of this report was required to be completed by 30 June 2009 so that the Minister for Mines and Petroleum could initiate necessary essential regulatory reform without undue delay.

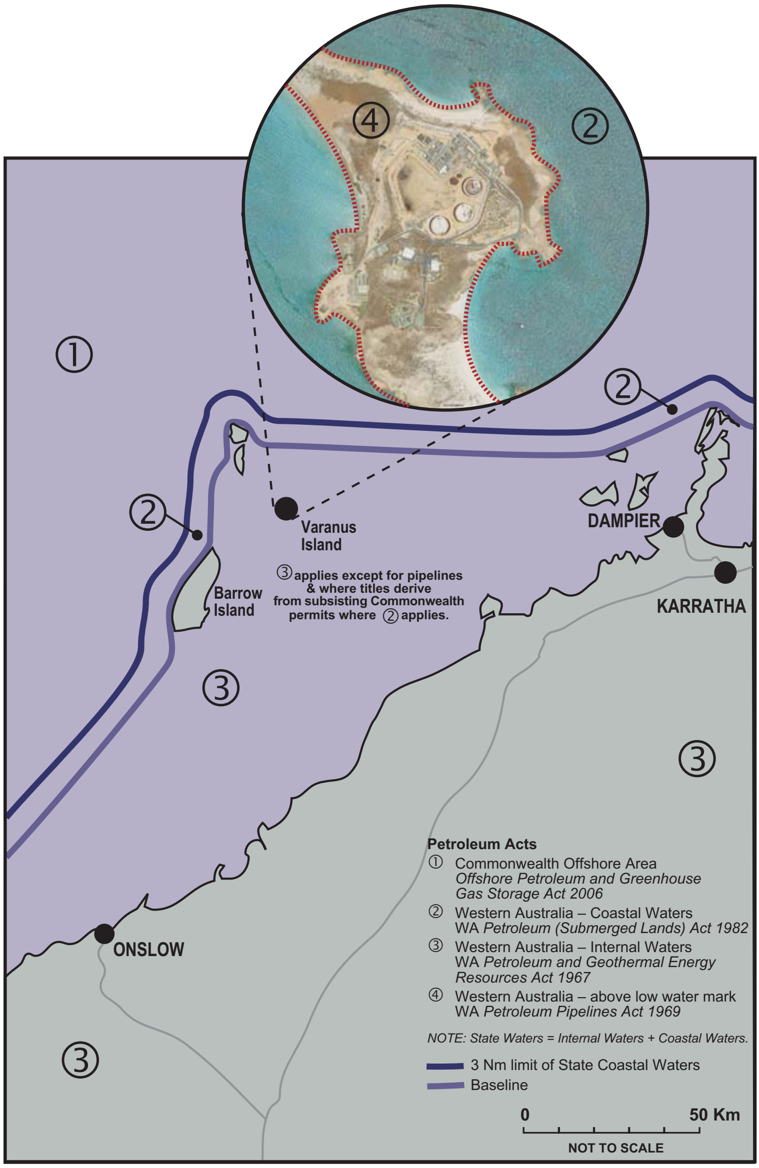
Varanus Island facility history and regulation

Varanus Island was first developed in the mid 1980s as a processing plant servicing offshore oil and gas reserves. In 1987, the facility started operation receiving oil and gas from the Harriet Oil Field northeast of the island. Since that time other reserves have come on stream, the production facilities on the island have expanded and new pipelines have been built.

The Varanus Island oil and gas facility is a complex and sophisticated production process. The site consists of a range of equipment including storage tanks, flare stacks, fractionation, columns, compressors, dehydration units, heaters and heat exchangers as well as utilities such as generators, accommodation, drinking water production and a heliport.

11 On 29 May 2009 the Apache response through its lawyers was that:
'1 the matters the subject of that [comprehensive root cause] investigation report are complex and must be completed properly;
2 there is no final report as yet;
3 my client does not have in its custody any drafts of that report; and
4 my client therefore has in its custody no documents which respond to this notice.
Documents provided to the independent expert for the purposes of producing that report are the subject of a claim of legal professional privilege.'

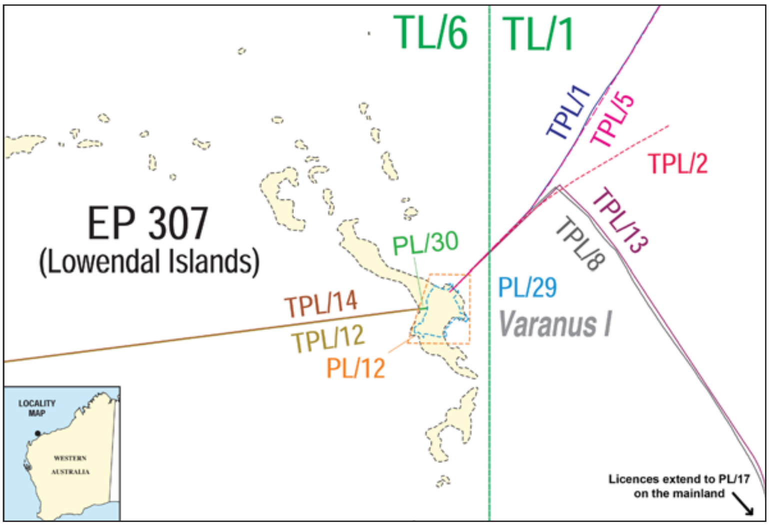
Figure 2: Relevant legislative boundaries



Varanus Island is classified as within Western Australian internal waters and, as such, falls under Western Australian State jurisdiction.[12] Western Australia chose to regulate the facility as a 'pipeline'[13] under the Western Australia *Petroleum Pipelines Act 1969* (WA PPA), which allows the Minister to declare 'a facility, or a facility of a class, specified in the order to be a pipeline facility.[14]

WA chose to use a single Pipeline Licence (PL12) to cover most of the facility down to the low water mark (PL29 and PL30 cover small areas relating to another joint venture on the island) and then used Directions to recognise and regulate issues such as safety. PL12 was issued in May 1985 for a period of 21 years, subject to inspections complying with the licence conditions. As new plant was added or other factors arose that affected the conditions of the licence, variations in the conditions were sought from the regulator. Over the 21 years of operation, some 17 variations were sought and granted.[15]

Figure 3: Varanus hub pipeline licence



12 Annex 1 provides an overview of the legislative framework for offshore and island petroleum activities and discusses relevant legislative boundaries in detail.

13 The PPA definition of a pipeline is very broad: 'Pipeline means a pipe or system of pipes used or intended to be used for the conveyance of petroleum; and includes all structures for protecting or supporting a pipeline and all loading terminals, works and buildings and all fittings, pumps, tanks, storage tanks, appurtenances and appliances.'

14 WA PPA Section 5.

15 PL12 is discussed in detail in Annex 4 and in chapter 2 on WA regulation.

In January 1995, Apache Northwest Pty Ltd took over the Varanus Island facilities and associated pipelines as operator. In so doing, they inherited the WA PPA directions as they applied to the PL12 pipeline license and a number of other pipeline licences. In December 2005 Apache submitted an application to renew PL12. Once an application for renewal is submitted, the existing licence remains valid until the renewal is either approved or declined. As at June 2009 this renewal has not yet been granted.

The introduction of the 'safety case'

In November 1990 Lord Cullen, a senior Scottish judge, handed down his findings and recommendations into the 1988 Piper Alpha disaster. His recommendations led to a radical change in the way major hazard industries, particularly offshore oil and gas, operated. A duty of care/co-regulatory approach using a safety case was adopted in the UK and Australia, progressively replacing previously prescriptive regulatory approaches to safety.

In essence, a safety case is an enabling document through which an operator assures the regulator that operations at a particular facility will be carried out in such a way that it ensures that risks are managed to a level that is as low as reasonably practicable (ALARP). The safety case describes the facility, provides details on the hazards associated with the facility and outlines the implemented risk controls, and describes the safety management system that will be used to minimise risk.

Under the duty of care/safety case regime, the operator is responsible for safety on the facility while the regulator provides assurance that the operator is managing risk. Under this regime, the safety case is developed by the operator then assessed and accepted by the regulator. The ongoing effectiveness of a safety case, the operator's compliance with it and the completeness of the operator's validation processes are all measured by the regulator through ongoing audits and inspections. Unlike a prescriptive regime where regulatory compliance is achieved through meeting a list of prescriptive requirements, an efficient safety case regime requires a technically savvy, highly competent regulator. Such a regulator uses a range of management tools including formal risk assessments to ensure that the risk associated with each operator and each facility is recognised and managed. In addition, the duty of care regulator must tread a middle ground recognising the risks of being 'captured' by industry while still ensuring that the operator is given the advice and guidance needed to ensure safety – while always ensuring that safety remains the responsibility of the operator.

In Australia, the safety case approach was first given effect by a 1992 amendment to the Commonwealth *Petroleum (Submerged Lands) Act 1967* (PSLA) requiring employers to provide a safe work place, equipment suppliers to provide equipment safe for purpose and the workforce to work safely within set procedures. This was then given effect through the *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996* (MOSOF) which provide operators with detailed information relating to safety cases, their contents and safety measures that shall be included, along with information relating to safety case submission, acceptance and revision. The amendment and regulations were subsequently mirrored by other States and by the Northern Territory in their offshore legislation.

The Western Australia mirroring legislation, the Western Australian *Petroleum (Submerged Lands) Act 1982* (WA PSLA) applies to state territorial waters out to three miles from the territorial sea baseline. Facilities in the waters immediately surrounding Varanus Island, including pipelines to and from the island, are located in inland waters but are subject to the WA PSLA and its associated regulations as an area where a subsisting Commonwealth permit applied[16]. On Varanus Island the safety case was introduced as a condition of the PL12 licence in 1998. This is not the same as a safety case under the Commonwealth or WA PSLA. While some key requirements as to the contents of a safety case are outlined in the licence condition, this does not give legal force to a safety case regime or provisions of the WA PSLA that are not spelt out in the licence documentation.

The formation of a national safety authority and its role on Varanus Island

In 1998 the Commonwealth committed to a review of the safety case regime in light of the extensive hydrocarbon exploration and exploitation on the North West Shelf, Bass Strait and off South Australia. An independent review was commissioned in 1999 and its initial report was issued in March 2000. The review identified a surfeit of regulations with unclear boundaries and inconsistencies, a lack of skills and capacity within the various regulators, and a lack of Commonwealth resources and credibility to drive the necessary changes. The final report, published in 2001, recommended a revision of the current legislation and the creation of a national petroleum regulatory authority.

16 See Figure 2 and Annex 1 for more detail.

In mid September 2002, the Ministerial Council on Mineral and Petroleum Resources (MCMPR) agreed to the formation of a single offshore safety authority covering both Commonwealth and State coastal waters. In September 2003, enabling legislation in the *Petroleum (Submerged Lands) Amendment Act 2003* led to the formation of the National Offshore Petroleum Authority (NOPSA). NOPSA commenced operations on 1 January 2005, headquartered in Perth with an office in Melbourne. NOPSA had responsibility for Commonwealth waters, and was conferred powers in State and North Territory waters after the NOPSA amendments were mirrored by each jurisdiction.

WA was the last significant jurisdiction to mirror the enabling legislation and, as a result, retained regulatory responsibility for safety in offshore areas covered by the WA PSLA until March 2007. In addition, the State retained responsibility for safety of offshore facilities in internal waters, including on Varanus Island. Unfortunately, basing NOPSA in Perth had the unintended consequence of making it a highly attractive employer for WA-based regulatory staff and as a result, NOPSA's creation led to an almost immediate migration of staff from the Western Australian regulator in DOIR to NOPSA.

This left DOIR with legislative responsibility for safety and integrity without sufficient technical staff to assure compliance with the regulations. Based on WA's intention to confer appropriate powers on NOPSA[17] the Western Australian Government entered into two 'Service Contracts' which would enable NOPSA to supply technical and auditing services to DOIR for an interim period from 1 January 2005 to 30 June 2005. In the continuing absence of enabling legislation, the service contracts were extended, initially by three months, then by 12 months and latterly two years.

As a result, when the Varanus Island pipeline rupture and fires occurred on 3 June 2008, regulatory responsibility for safety under the PL12 licence rested with DOIR, with NOPSA providing technical advice and contractor services including audits and inspections under a service contract.

17 Directly in the case of the WA PSLA, and indirectly through contracts for internal waters.

Responding to the Terms of Reference, we have divided the report into four chapters:

- *Chapter 1: Apache's practices, documentation and foreseeability.* This chapter investigates in detail what Apache knew in the lead up to the incident and what was raised in audits by the safety regulator, and how Apache responded to this information.
- *Chapter 2: Better practice and the evolution of a safety culture.* This chapter considers available standards and industry better practice regarding pipeline management with a specific focus on shore crossings and cathodic protection. It also considers information sharing and the availability of information which would have enabled Apache to better manage the 12 inch SGL, and considers Apache's culture and the company's approach to safety issues.
- *Chapter 3: Regulation of Varanus Island and the 12 inch SGL.* This chapter considers the role of the main WA regulator, DOIR and the roles of DOCEP and NOPSA in providing services to DOIR, the regulatory environment relevant to the shore crossing at Varanus Island, and overall integrity regulation in Australia.
- *Chapter 4: Causal Factors, Scenarios and Conclusions.* This final chapter reviews the technical causes for the explosions on the basis of key factual material including testing results and data obtained since the initial report of 7 October 2008, considers the most likely corrosion scenarios and presents conclusions in light of these and other factors from the preceding chapters.

Although this investigation focuses on facilities and pipelines located on Varanus Island that are licensed under the WA PPA, documents, information and guidance or advice received relating to any of the Varanus Island Hub operations (which includes facilities and pipelines regulated under the WA PPA, WA PSLA and Commonwealth OPGGSA) are relevant to this investigation due to the interconnected nature of the operations.

1: Apache's practices, documentation and foreseeability

> *Apache disagrees with any conclusions drawn at this time about this unforeseeable event because they are premature and misleading, said Tim Wall, Managing Director of Apache Northwest Pty Ltd.*
>
> Apache media statement of 10 October 2008 in relation to the DOIR/NOPSA Varanus Island investigation report

> *The explosion at Varanus Island was not reasonably foreseeable, and was not within Apache's reasonable control or able to be reasonably prevented by Apache.*
>
> Apache formal response of 6 February 2009 to the DOIR/NOPSA Varanus Island investigation report

> *Lloyd's Register spent nearly 500 hours auditing Apache's procedures and 37 days on Varanus Island physically inspecting Apache's pipelines and facilities, which culminated in a formal report validating the island's plant and facilities as fit for operation for the next 21 years.*
>
> Apache formal response of 6 February 2009 to the DOIR/NOPSA Varanus Island investigation report

1.1 Any incident involving potential multiple fatalities or major loss of integrity may entail a failure of safety critical management systems, including integrity management, and a failure by the operator to assure a safe working environment. When any such failure occurs the immediate test of reasonableness should be applied: could the incident have reasonably been foreseen or was it reasonably foreseeable?[1] It is important to understand any systemic failures that led to the incident, and we have considered these through our examination of failure scenarios in chapter 4.

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1 Turner, B. (1978) *Man Made Disasters*, London; Wykeham. The basic premise on which this seminal text is based is 'the failure of foresight'.

1.2 We believe that the arguments put forward by Apache that the explosion at Varanus Island was unforeseeable and Apache's other comments about lack of control (as indicated in the quotes above) can be seen as symptomatic of a narrow and reactive approach to safety based on fear of potential legal liability rather than seeking to learn and share the lessons behind the incident. The company's focus on the technical root cause of the incident, is likely to be similarly narrow and self-serving, perhaps emphasising a type of rapid corrosion that could not have reasonably been detected in time[2]. We have experienced the full armoury of legal argument and obstacles in our own interactions with Apache. In short, Apache does not appear willing to examine organisational or cathodic protection issues that may have contributed to the explosion, with a view to minimising the likelihood of the occurrence of a similar event at Varanus Island or other similar facilities.

1.3 The following sections of this chapter document and analyse the information available to Apache prior to the explosion at Varanus Island that should have enabled the organisation to foresee an event of this type. This includes documents produced by consultants for Apache's internal use, documents produced for regulatory purposes such as safety cases, the Lloyd's validation and the pipeline management plan, and reports and recommendations from regulatory audits. The potential contribution of organisational factors to this incident is discussed in more detail in chapter 2.

Apache documentation demonstrating what was available and known from 1995 to 2008

1.4 From 1995–2008 Apache sought and received ongoing business-related information concerning all aspects of its Varanus Island operations as a normal part of its business. It sought and received safety-related information from discrete sources for specific purposes, as well as safety information embedded in the general information flow. Discrete pieces of information are not necessarily relevant by themselves. However, when collated and analysed, they provide the 'ability to see the big picture' necessary for the effective safety management of complex processes. We argue that information generated by/provided to Apache demonstrates the company could reasonably have foreseen the increasing risk of an integrity failure involving the 12 inch SGL and could have taken steps which may have prevented this. This would have required appropriately trained and competent professional staff with corporate

2 A detailed discussion of investigations, including the stop rule, and Apache's response to the initial technical investigation is at Annex 2.

memory and time to assess trends and examine potential gaps, and a longer term view on maintenance and integrity management.

1.5 The following section examines three key classes[3] of safety-related information that were available to Apache to inform better decisions about pipeline integrity:

- Internal documents and consultancy reports that raise potential concerns since Apache took over the original Varanus Island facilities in 1995 as operator;
- Documents prepared for the regulator, including:
  - The July 2002 Varanus Island hub safety case;
  - The July 2007 Varanus Island hub safety case revision;
  - The 2006–2007 PL12 licence renewal Lloyd's Register validation process;
  - The 2008 Pipeline Safety Management Plan; and
- Information from regulators' safety audits, recommendations and requests.

Apache's internal documents and consultancy reports

1.6 The Investigation team reviewed all of the relevant Apache documents available to us in order to assess whether they foreshadowed a possible external corrosion issue with the pipeline in the area of the rupture, whether such a rupture's potential as a major accident event was documented and mitigated, and to assess Apache's systems more generally. Inevitably, what follows cannot include the large volume of material on integrity and maintenance across Apache's total North West Shelf operations. We also did not have access to Apache's long promised comprehensive root cause investigation report on the incident despite more than 12 months having elapsed after the Varanus Island incident.

1.7 We believe that the following documents are most relevant to the Investigation. Most were provided by Apache under compulsion pursuant to section 63 of the WA PPA. There may be other relevant documents held by Apache that we have not seen. The documents are summarised in chronological order from 1995, when Apache purchased and began operating the Varanus Island hub including the 12 inch SGL to the mainland that had been operated since 1992.

3 In addition to the externally available material available to Apache such as investigations by the NTSB, TSB, CSB, DSB and ATSB, regulator websites, industry seminars and conferences, standards development, safety culture material, etc which are canvassed in chapter 2.

An assessment of the relevance of these documents is made at the end of this chapter.

March 1991 – JP Kenny – Harriet Gas Project Technical Specification

1.8 The original technical specifications for the Harriet Project pipelines was produced by JP Kenny in 1991 and were intended to be used to inform the tendering process and to support regulatory submissions. JP Kenny also installed the 12 inch SGL. Specifications for the offshore section of the 12 inch SGL and for the shore crossing were a design pressure of 14.6MPa and design temperature of 60°C with a corrosion coating of FBE or asphalt enamel and a metal thickness of at least 11.1mm. The specifications propose:

> *...the Sales Gas Line may from time to time be inspected by an Intelligent Pig to monitor the internal condition of the line. Provision will be made for launching and receiving such pigs. ... [However] A zero corrosion allowance is made in the Sales Gas Pipeline, since this carries treated dry gas with no free water.*

1.9 The document presents most specifications in detail, except for the CP system:

> *Design of the Cathodic Protection system for the offshore pipeline will be in accordance with DNV 'Recommended Practice RP B401 for Cathodic Protection Design' (1986). Design of the Cathodic Protection system for the onshore pipeline will be in accordance with AS2832 'Cathodic Protection of Metals, Part 1, Pipes, Cables and Ducts' (1985).*[4]

1996 – Apache's Sales Gas Pipeline Survey Report

1.10 The Apache Energy Sales Gas Pipeline Survey Report issued on 20 February 1995 and updated with photos on 7 January 1996 and 8 July 1996. The survey was conducted by an Apache technician and a Wescor consultant from KP0 at the mainland shore crossing of the SGL to Compressor Station 130 km inland. CP readings were also taken for the KP0 support frame and for the offshore pipeline:

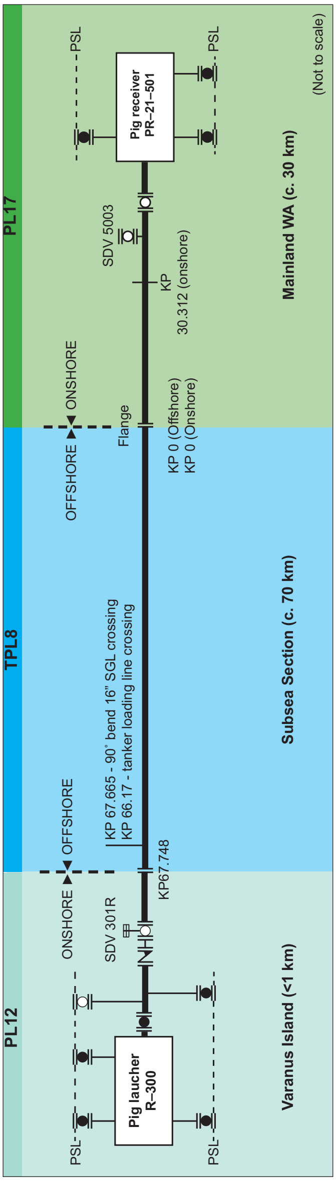
> *...the offshore pipe was -1.147V, confirming both full protection at this end and isolation from the frame and onshore pipe (-1.305V).*

4 As noted in Annex 21 on Standards, there was a long-standing gap in the standards which failed to recognise and cover the shore crossing section.

1.11 For the onshore SGL mainland:

> *The survey results confirmed the pipe is fully protected for the entire length with potentials typically ranging from -1.292V to -1.458 (CP ON) … Surface soil conditions were generally very dry except the tidal flats section. The survey was conducted approximately three weeks after heavy rains were reported in the area.*

Figure 4: 12 inch SGL and licenses



1996 – Apache's Statutory Inspection Manual

1.12 Apache's 'Statutory Inspection Manual' was last revised on 11 September 1996.[5] Amongst other things, the manual covers Apache's periodic inspection requirements for the 12 inch SGL from Varanus Island to the shore crossing on the mainland (licence TPL8) and from that shore crossing to 'compressor station 1' on the mainland (licence PL17). The manual makes no reference to the inspection of the short section of the 12 inch SGL at the shore crossing onto Varanus Island[6] covered by PL12 where the ruptures and explosions occurred on 3 June 2008.

1.13 The Manual notes the general requirement for pipeline inspections specified in AS2885:1987 and that this includes wall thickness measurements and corrosion protection surveys. It states:

> *The Sales Gas Line (SGL) will require a detailed survey one year after installation. ... The pipeline licence requirements for PL/17 and TPL/8 are that an annual external survey be carried out after the cyclone season. It is proposed that these annual surveys be carried out in the second quarter of each year. Furthermore the requirements of AS2885 state that the pipelines be regularly inspected (ref cl 13.4.2) and that potential surveys be carried out at intervals of not more than one year (ref cl 6.9.3.3) for the onshore pipeline (PL/17).*[7]

1.14 The Manual also stated that pipeline inspections could include 'Internal inspections using an intelligent pig'[8] but this was not then applied to the 12 inch SGL. The Manual was superseded in mid 1997 by an 'Underwater Pipeline Inspection Manual' and an 'Onshore Pipeline Inspection Manual' with the former itself superseded in June 2003 by an 'Underwater Inspection Manual'.

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5 Prior to this, the Hadson (Hadson was the majority joint venture owner prior to Apache) *324mm Onshore Sales Gas Line (PL/17) Pipeline Inspection Detailed Report May 1993* was produced on 15/12/93. It states that 'The onshore sales gas pipeline comprises of 30km offshore pipeline of 324mm diameter x 9.5mm wall thickness line ERW pipe, API 5L Gr X52 material coated with extruded HDPE corrosion protection coating. Cathodic Protection is provided by stand off magnesium and zinc bar anodes. The pipeline runs from the mainland shore crossing at KP0 to SECWA compressor station CS1.' It noted that mandatory documents included the AS2885-1987 Pipeline Code.

6 Appendix Section II referred to a 12 inch SGL survey by ROV from 'Varanus-KP0'.

7 The same could have been said for the PL12 section of the 12 inch SGL that included the shore crossing for which annual post-cyclone inspections were also a licence condition.

8 An intelligent pig or in-line inspection (ILI) device is an instrumented device pumped through the pipeline to assess any metal loss as a result of corrosion or other integrity issues.

1997 – Ferrum Technology – Cathodic Protection Review

1.15 A Cathodic Protection Review by Ferrum Technology Pty Ltd is linked to a 'QCL International Review of Apache SGL Cathodic Protection Survey Reports' and was dated 23 January 1997. The report abstract states with respect to the 12 inch SGL that:

> *The report reviews Westcor's recent cathodic protection survey, performed in December, 1997 on Apache SGL 324mm pipeline. A preliminary design for a new parallel pipeline onshore sales gas line is also included in this report. However, full design details will require soil resistivity data to be supplied.*

1.16 The main report states:

> *Based on Apache Energy Limited's cathodic protection criterion of -0.850V with respect to a saturated copper sulfate reference electrode, the pipe-to-soil measurements obtained by Westcor Engineering Pty Ltd during the 1997 cathodic protection survey reveal that the pipe is fully protected. The maximum and minimum pipe-to-soil potentials were -1.174V (KM1.95) and -1.325V (KM 24.642) respectively. However, based on earlier CP survey reports, it was noted that the current requirement for the pipeline is very dependent upon the moisture content of the soil.*

1.17 The report states further that:

> *It is difficult to quantitatively determine the condition of the extruded HDPE coating based solely on the data obtained from the CP survey … Since the current density has not increased with time, it is reasonable to assume that the coating condition has not significantly changed since 1993. ..: At this stage a DCVG survey is not recommended. It would be more cost effective to perform this survey when the new parallel pipeline is installed. … It is not possible to determine the need for an intelligent pig inspection survey based on CP data. Normally, after a certain period of time, it is mandatory to perform this type of survey on sub-sea pipelines. In this particular case, it would be prudent to continue the pigging survey over the onshore section of the pipeline, especially if this type of data has not been previously obtained.*

1.18 In commenting on the design of a CP system for the new 16 inch pipeline, it is stated:

> *Where possible, avoid any air-to-soil interfaces particularly where the sub-sea pipeline connects to the onshore pipeline, since this is a difficult location to access with inspection and pipe recoating equipment.*

1997 – Apache's Onshore Gas Pipeline Cathodic Protection Survey

1.19 The Apache Energy Onshore Sales Gas Pipeline Cathodic Protection Survey report was issued on 18 December 1997 and produced jointly with Westcor Engineering Pty Ltd with whom the survey was conducted during December 1997. It covers the section from KP0 to the metering station MLV 11 at Compressor Station 1 at the Dampier-Bunbury Natural Gas Pipeline (DBNGP). The survey tested the effectiveness of the installed cathodic protection system for compliance with the original design criteria which required a pipe to soil potential equal to or more negative than -0.85V measured with respect to a copper/copper sulphate reference electrode. For the KP0 frame and offshore pipeline, potentials on the support frame were typically -1.091V while:

> *The offshore pipe was -1.149V confirming both full protection at this end and isolation from the frame and onshore pipe (-1.178V). [For the onshore SGL] potentials typically ranged from -1.178V to -1.325V (CP ON) … Surface soil conditions were very dry except the tidal flats section.*

1998 – Stratex Pty Ltd – 12 and 16 inch Sales Gas Lines offshore section – AS 2885 risk assessment

1.20 Stratex Pty Ltd's 11 August 1998 report reviews the offshore sections of Apache's 12 inch SGL against the risk assessment material incorporated in the then current Australian Standard AS 2885 prior to the installation of the 16 inch SGL in 1999. Apache personnel, consultants and others conducted risk assessment workshops in June and August 1998 that identified nine action items. Action item three read: 'External Corrosion – At the Varanus Island shore crossing: Ensure the procedures cover the need for inspections at the shore crossing on Varanus Island.' An Apache employee is listed as 'action nominee' to meet an 'action close-out date' of 30 September 1998.

1.21 A more detailed attachment noted that a 'credible' threat existed at the mainland shore crossing section of the proposed 16 inch SGL and listed a procedural measure of 'Inspections at the water level'. The same attachment also cited the 'credible' threats of 'Stray current corrosion – lines close to each other. Debris in trench. Possible breakdown of coating from abrasion where pipelines cross' and 'Failure of the concrete coating'.

1998 – QCL International – Corrosion risk assessment and inspection scheme report

1.22 This September 1998 corrosion risk assessment report commissioned by Apache covered a number of facilities including the entire 12 inch SGL. The report noted:

> *Pipelines are also at risk from external corrosion. All pipelines under study in this report are protected by external coatings and cathodic protection, which if maintained properly are highly reliable. The variable nature of the external conditions means that prediction of external corrosion rates is unreliable. ... It is assumed that the cathodic protection system is properly designed, and if functioning correctly will prevent significant corrosion in the pipeline. Design review of the CP system is outside the scope of this report. ... If CP tests show significant unacceptable performance, physical pipe inspection will be necessary.*

1.23 In assessing hazards on the SGL, the QCL report stated that:

> *The pipeline contains high pressure hydrocarbon gas. A failure in the bulk of the length of the pipeline would be far removed from human activity, so would be an economic consequence only. However, a failure in the immediate vicinity of Varanus Island or on the mainland could endanger life.*

1.24 The report stated that the 12 inch SGL faces a most significant risk due to external corrosion in the coastal and onshore sections. The focus was on the mainland shore crossing end of the pipeline where mangroves are located, but some of the sea water conditions and tidal effects mentioned which 'mean that the coastal section is more at risk of external failure than any other part of the pipeline' are potentially common to the Varanus Island shore crossing section of the same pipeline.

1.25 The 1998 QCL report includes the heading 'On-line Inspection' and states:

> *The requirement for intelligent pigging on this line is dictated by the external corrosion hazard, particularly in the coastal mangrove section of the line. The most serious risk to the continuing integrity of the pipeline is where coating has disbonded, creating a region of wet, bare metal shielded from cathodic protection current. Corrosion may occur despite adequate cathodic protection potentials. This is a risk on all coated pipelines, but is most significant on onshore/inshore lines, particularly under tape wraps and shrink-wrap type field-weld coatings. The only methods of detecting such failures are either to excavate all field joins, or to run an intelligent pig. The economic and safety consequences of a failure of the*

Sales Gas pipeline, coupled with the difficulty of surveying the coastal section, and the risk of a coating disbondment failure mean that regular intelligent pigging of the line is justified. To save cost, this survey may be concentrated on the coastal and onshore sections of line. The period is arbitrary – a figure of 5 years is suggested, meaning that an intelligent pig run will be necessary next year. Further surveys will be required depending upon the results.

2000 – Apache's production facilities integrity corrosion management strategy

1.26 On 24 February 2000, Apache issued a 'Production Facilities Integrity Corrosion Management Strategy' which focussed on the threat posed by corrosion including corrosion to pipelines and corrosion under insulation (CUI). It listed a significant number of management and technical staff and consultancy positions with roles and responsibilities to address this threat. The document states:

It is a major objective of the corrosion management system to ensure safe working and avoid environmental damage. This will be achieved for offshore installations, onshore plant and pipelines by meeting the statutory requirements in both their current and emerging forms. The Corrosion Management Process conforms to the requirements of the current legislation as provided in the Petroleum (Submerged Lands) Acts[9]*. It also observes the requirements of the Australian Standards that are expected to be applied by the legislation and by operating licences and consents issued in accordance with the legislation.*

1.27 The Apache document goes on to define the policy and practice of Corrosion Risk Assessment (CRA) in terms of failure likelihood and associated consequences. In discussing monitoring, the document notes the various purposes of pigging pipelines using different types of pigs, including for inspection:

'Intelligent' pigging of a new pipeline prior to operation will provide an initial 'signature' of the conditions of the pipe internal walls and wall thickness. Thereafter intelligent pigging runs are scheduled to inspect the condition of the pipeline.

9 Although this investigation focuses on facilities and pipelines located on Varanus Island that are licensed under the WA PPA, documents, information and guidance or advice received by Apache relating to any of its Varanus Island Hub operations (which includes facilities and pipelines regulated under the WA PPA, WA PSLA and Commonwealth OPGGSA) are relevant to this investigation due to the interconnected nature of the operations.

Factors affecting the schedule and frequency that relate to corrosion control are: … increased corrosion rates indicated by other monitoring devices.

1.28 Among other testing methods listed in the Apache document are monitoring cathodic protection, use of corrosion coupons, sand probes and non destructive testing (NDT) techniques which include 'Visual Examination, UT (A Scan and B Scan), Radiography, MPI, Dye Pen, pit depth gauging, boroscoping and ACM pitting depth surveys'.

2000 – JP Kenny – Pipeline Asset Inspection Strategy

1.29 JP Kenny produced for Apache a Pipeline Asset Inspection Strategy issued for comment in April 2000. It included a table 2.1 'Summary of Proposed Prescriptive Inspection Strategies' stating for the 12 inch SGL that it had been operating since 1993, had a length of 100.06 km, external survey was to be at two yearly intervals CVI [comprehensive visual inspection] by diver/remotely operated vehicle (ROV), internal survey was to be at five yearly intervals by ultrasonic testing, and CP survey at four year intervals with CP measurements by diver/ROV.[10] Ultrasonic testing was referenced to AS 2885.3 and the latter was stated to be:

Ultrasonic testing of pipewall using equipment mounted externally on prepared areas of pipeline. Air divers required. Note this operation requires pipeline coatings to be removed.

1.30 CP was linked to standards DNV RP B401-1993 and AS2832.1-1985. The objective of external inspection was stated to be 'stability' of the pipeline, for internal inspection it was 'establish integrity' of the pipeline, and for CP it was 'To ensure that the cathodic protection system (sacrificial anodes) continues to protect the pipeline and associated infrastructure from corrosion'.

1.31 An attachment to the JP Kenny report provided more detail on each of the pipelines with the 12 inch SGL from Varanus Island to Compressor Station 1 as supplying dry gas to the DBNGP over 100.060 km through 323.9 mm outside diameter pipe of steel grade API 5LX60 with a minimum yield strength of 413, design pressure of 14.5, design life of 25, nominal wall thickness of 11.1 (offshore), maximum inlet temperature of 80°C, external corrosion protection of 4.5 mm Asphalt Enamel coating and sacrificial cathodic protection, and 'Treated dry gas so no internal corrosion expected'. Another table of 'Pipeline Licence Inspection Requirements' noted

10 In the same table, the 1992 Campbell/Varanus Island Infield line of 31.15km differed only with respect to internal survey being intelligent pigging at five year intervals instead of ultrasonic testing. The 1999 16 inch SGL had the same internal testing proposed as the 12 inch SGL.

for the 12 inch SGL that external survey requirements were 'Annual post-cyclone', internal survey requirements 'In accordance with approved plan (Code), CP survey requirements 'Annual corrosion & damage inspection of above ground pipeline (Code), and Pipeline Code AS2885-1987. It was noted that:

> *Only licences pertaining to pipelines listed. This includes short onshore sections where applicable, but not hydrocarbon processing plant where piping is covered by ANSI B31.3. Licences do not stipulate a particular revision of a code. The latest at the time of pipeline construction has been assumed. AS2885.3-1997 Clause 5.2.2 states: 'The regularity of assessment should be based on the past reliability of the pipeline, current knowledge of its condition, the rate of deterioration and statutory requirements'. …in cases where licence and code requirements differ fundamentally, both are indicated.*

1.32 The report also tabulates a summary of code requirements and for AS2885-1987:

> *External Survey Requirements … Pipeline route to be inspected on an approved periodic basis or when damage may have occurred. … Coated Pipeline – external coating survey whenever visible, interval not specified. … Internal Survey Requirements … Otherwise by approved method, interval not specified. … CP Survey Requirements … Review within 1 year of installation. Monitoring at 5 year intervals (may be shortened towards end of life).*

1.33 A table with the JP Kenny recommended program included for the 12 inch SGL External Survey at two year intervals, Internal Survey at five year intervals, and CP Survey at four year intervals. Finally, the 12 inch SGL was listed among 'Pipelines to be inspected by ultrasonic testing at critical locations at five year intervals,' 'ultrasonic testing at regular separations and identified 'hot' spots', and 'necessary to confirm moisture control system' to ensure dry gas.

2000 – JP Kenny – Shallow Water Pipelines Span Assessment

1.34 This report involved consultants JP Kenny performing a span assessment of a number of Apache's subsea pipelines based on ROV inspection in April 2000 by Tamboritha Consultants. The 12 inch SGL was reportedly inspected from KP18.980 – 69.012 using the ROV underwater. Of 500 anomalous freespans across all pipelines, approximately 60 per cent were eliminated by JP Kenny, including all 71 on the 12 inch SGL.

2000 – QCL International – Apache Asset Integrity Management Audits

1.35 QCL International provided the then WA regulator[11] with the following four 'Apache Asset Integrity Management Audits' on 27 July 2000.

- A Lloyd's Register validation requirements audit checklist sheet dated 5 May 2000 states that the database has no trending facility available for mechanical problems (re 'PRDs') but this 'Was only a recommendation from Lloyd's Register, not a requirement'.
- A Corrosion Data Management Procedure Audit Checklist dated 5 May 2000 states that a 'centralised corrosion database does not exist at the moment' and 'asset lives are not calculated at the moment'.
- An audit of 24 May 2000 re Apache's Pressure Vessels, PRDs & Pipework Database states:

  A lot of Lloyd's Register validation requirements have already been implemented. However, a lot of work is still required. … It must be noted that a lot of Lloyd's comments are only recommendations and don't necessarily require to be implemented, if otherwise justifications exist.
- An audit of 24 May 2000 re Corrosion Data Management Procedure – East Spar Monthly Corrosion Reports states:

  Only calculated Asset lives, based on measured corrosion rates, must be added to the report. One concern raised by the audit was the completeness of the reports. It was found that a lot of information to be provided by … [the corrosion technician] was missing on a regular basis. In addition, it was not possible to ascertain the accuracy/quality of the data collected on the Island. It was found that QCL could not answer a lot of the questions related to data gathering, and could not show evidence of compliance with the procedure regarding frequency of data gathering and accuracy of data.

2001 – Apache's Corrosion Management System Pipework Inspection Procedure

1.36 An Apache Corrosion Management System Pipework Inspection Procedure was issued on 4 February 1999 and revised on 19 June 2001. The focus was on pipework rather than pipelines. It stated that 'Visual inspection should only take place by competent inspection personnel as laid out in AS 4041:1998 Section 8.1.3,

11 At that time the Department of Mines and Energy.

and AS 4481:1997 Section 4.' When an anomaly is found, the document states that:

> *A second tier of inspection is activated, consisting of detailed recording of the anomaly and 'checking' for other anomalies. The checks comprise further prompts for inspection to identify the cause and/or other associated defects related to the original anomaly.*

1.37 A table of anomaly criteria included corrosion and weight coating. For corrosion, the criteria for an anomaly was described as 'pits greater than 2 mm or leading to a wall thickness less than the anomaly wall thickness.' A wall thickness anomaly was described as 'less than 80 per cent of nominal wall thickness of pipework'.

2002 and 2003 – Auscor – Onshore Cathodic Protection Survey

1.38 In June 2002 and July 2003, Auscor Pty Ltd undertook onshore CP surveys for Apache on the 12 inch and 16 inch SGLs. The reports provided to the investigation cover only the mainland end of the pipelines. The June 2002 report refers to Australian standards AS2832.1 and AS2885 and states that:

> *...the minimum protective potential for gas pipelines is -0.85V with respect to copper sulphate reference electrode. This criteria is increased to -0.95V for the tidal flat section where there is a likely presence of sulphate reducing bacteria.*

1.39 Further, it is stated that 'both pipelines are fully protected with potentials relatively consistent and ranging from -1.145 to -1.272V, well above the minimum -0.85/-0.95V criteria.' After an extended 18 month dry season, the 12 inch SGL range was from -1.176V with CP off to -1.272V with CP on. In July 2003, after 'a period of intermittent heavy rain which would have increased general soil moist levels to pipe invert level' the 12 inch range was from -1.085V to -1.312V with CP off and from -1.242V to -1.404V with CP on.

2004 – QCL International Ltd – Review of Apache Energy pipelines

1.40 Apache contracted QCL International to conduct a review of its Varanus Hub pipelines and on 6 February 2004 the review team delivered their report. Its summary of results included a section 'Missing Data and Assumptions' which included the finding that:

> *In general it was found that very little inspection data was available for onshore pipeline sections on Varanus Island, shore zone sections and subsea risers. The onshore pipelines*

on Varanus Island are monitored visually during standard operations on the island and inspection data is therefore often not documented. ... At present the shore zones do not seem to be included in either of the standard inspection work scopes.

1.41 The report considered pipelines in separate zones, according to operating environment changes, with the following five discrete sections on the SGLs considered: Onshore pipeline Varanus Island; Shore zone pipeline; Subsea pipeline; Shore zone pipeline mainland; and Onshore pipeline mainland. The Varanus Island 'shore zone' section was described as being 0.32 km long beginning at the isolation joint (KP69.76) and ending in the shallow water shore zone (KP69.445).[12] The consequence of failure for each section was assessed against four factors: personnel safety, asset damage, production loss and environmental damage.

1.42 In relation to shore zones, QCL stated that:

...these sections are considered to be protected by the subsea pipeline anodes. The probability of section failure due to external corrosion is therefore assessed on the basis of CP readings and anode wastage inspection data. The primary indications of external corrosion are assumed to be sudden changes in CP trends and high or low CP readings accompanied by a very high or very low anode wastage rate.

1.43 The QCL report also stated that:

Alternatively no cathodic protection may be used on short onshore pipeline sections with an external corrosion protection coating. The availability of inspection data is again used to provide a confidence factor for the assessment of each system. ... The pipeline inspection history is then reviewed for indications of damage to the external coating and the isolation joint. ... No inspection data was available for the onshore section on Varanus Island or the shore zones at Varanus Island and the mainland. This has resulted in increased risk rankings in these sections.

1.44 The appendices show that there was no data of any kind available to QCL on the 12 inch SGL in these sections including from CP surveys or physical inspections. All of these sections were assessed as of 'medium' risk of external corrosion with consequences being 'critical' and the overall risk level 'high'.

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12 The report did not address partial protection in that area of the beach crossing where the pipelines were buried in shallow trenches and subject to a wet/dry regime through seasonality and the diurnal rhythm of the tide. QCL (now iicor) submitted to us that it assessed risk for this section as 'high' for the purpose of prioritising resources in areas not ALARP.

1.45 The report recommended that a general visual inspection of the pipeline be implemented as soon as possible and assessment rerun for these sections.

2004 – Netlink Inspection Services – Varanus Island ultra shallow water and onshore pipeline inspection – 12 inch Sales Gas Line

1.46 Apache contracted Netlink Inspection Services to undertake a visual inspection of the 12 inch SGL from 16-18 October 2004 that included the shore crossings. The report states that:

> *All items of corrosion noted on the Sales 12" Gas Export line were on the western side of the Cyclone Protection Enclosure [including] width 500mm length 300mm corrosion visible under wrap. ... Close to the beach, and as the pipeline enters the shore, there are two sectors of missing weight coat. As the 12" Sales Gas Export line enters the sand dune at the end of the North Eastern beach on Varanus Island there is also a minor crack in the weight coat.'*[13]

2006 – Apache's annual summary report of inspection and corrosion management activities

1.47 This Apache report was drafted in May 2005 and issued on 4 January 2006. In relation to the 12 inch SGL, it summarises the Netlink Services inspection of 16 October 2004. It also includes extensive material on inspections, including intelligent pigging, of other pipelines completed during 2003, 2004 and in May 2005.

2006 – Apache – Onshore Pipeline Inspection Manual

1.48 In mid 1997, Apache issued its 'Onshore Pipeline Inspection Manual' which was updated in 2003 and most recently reissued for use on 22 March 2006. The Onshore Pipeline Inspection Manual provided the overriding philosophy and expectations for onshore pipeline inspection.

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13 Prudent engineering practice would be to remove the wrapping and assess the remaining wall thickness in the corroded section of the pipe. If the pipe wall thickness was within tolerance, then the pipe would be re-wrapped and the inspection program for the shore crossing section of the pipeline would be modified to reflect possible higher localised corrosion rates. Any issues with the efficacy of operation of the cathodic protection system should also have been considered.

1.49 The manual preface stated:

> *This Onshore Pipeline Inspection Manual covers the inspection of all the onshore sections of these pipelines, defined as that part of the pipeline between the landfall to the pipeline termination or pig launcher/receiver.*

1.50 However, its description of coverage then becomes somewhat confused. The 'scope of manual' section states that the SGL covers licence TPL8 from Varanus Island to the mainland with no mention of the extent of pipeline covered by PL12, which applied to all six pipelines at the north east shore crossing on Varanus Island. It then states:

> *...two SGLs ... transport processed dry gas from East Spar and the Harriet Gas Gathering project on Varanus Island to the Alinta Gas pipeline at compressor station CS1, 30.3 km of both the pipelines is onshore and thus is covered by this manual.*

1.51 It is unclear whether the 30.3 km includes the small section on Varanus Island under PL12 or not. The Manual further stated that pipeline inspection should include:

> *...an audit of corrosion control facilities to assess their effectiveness. This includes cathodic protection systems, pipeline coatings. ... The pipeline licence reinforces the requirement of AS2885.3 ... [which] states that pipeline surveillance and inspection shall be conducted at a frequency based on the past reliability of the pipeline, historical records, current knowledge of its condition, the rate of deterioration and statutory requirements. ...this inspection frequency approach introduced in 2001, AS2885.3-1997 gave inspection frequency as annually. It is envisaged that no risk assessments have been conducted, and annual frequency is to be applied until these documents are in place.*

1.52 The Manual provides direction for corrosion control procedures. Above ground pipeline coatings should be addressed with particular attention to crevice areas like pipe supports and the underside of the pipeline, as well as areas of blistered or disbonded coating. It states that assessment of below ground pipeline can only occur through monitoring CP data or the use of special coating defect surveys such as Pearson or DC pulsed or Voltage Gradient surveys, and visual surveys where the pipeline is exposed at selected locations.

1.53 The manual also provides direction on assessments of CP. It states that test results outside the range of 850 -1200mV are considered 'anomalous' and 'shall be' subject to detailed evaluation.

2007 – ModuSpec Australia Pty Ltd – Review of recommendations from 2004 pipeline risk assessments; and 2007 – Gap Analysis: Comparison of QCL review with the requirements of AS2885 and the Petroleum (Submerged Lands) Pipelines Regulations 2001

1.54 ModuSpec Australia Pty Ltd produced these two reports, dated 10 April 2007, with reference to all Apache pipelines related to Varanus Island. The Gap Analysis was undertaken as part of the work towards a proposed Apache pipeline management plan. With respect to the 12 inch SGL, the report notes that the pipeline:

> *...is 100 km long. The pipeline is constructed of carbon steel and has an external corrosion coating of Asphalt Enamel from Varanus Island to the Mainland and is coated by Extruded HDPE on the onshore section of the Mainland. Cathodic protection is achieved by the use of bracelet anodes. The pipeline was designed to the AS2885-1987 standard and installed in 1992.*

1.55 The report states that 20 recommendations had been made with respect to the pipeline with three remaining open, including one regarding external corrosion on the onshore mainland section.[14] The report's 'summary of integrity' table includes the four categories of external corrosion, fatigue and instability, impact/accidental damage, and internal corrosion; and lists five pipeline sections including 'Onshore Pipeline Varanus Island' and 'Shore Zone Pipeline Varanus Island'.

1.56 The 2004 ModuSpec Gap Analysis findings state with respect to QCL's 'risk identification' in 2004 that while the threat posed by a likelihood of failure as a result of external corrosion was assessed against four consequence factors – personnel safety, asset damage, production loss and environmental damage - threats not assessed included 'external interference, operations and maintenance, design defects, material defects, and intentional damage' and:

> *In addition, the threats were not categorised in accordance with AS2885.1 (i.e. those which are not credible; those which are controlled by external interference protection; those which are controlled by design and/or operational procedures or residual threats requiring further risk evaluation).*

14 The 2004 inspection of the pipeline by Netlink was 'reviewed in a April 2007 audit by ModuSpec, with the comment that 'CTC-2 CP survey deemed protected against external corrosion under aerobic and anaerobic conditions'. It was deemed that this corrosion issue had been closed in October 2004.

1.57 In terms of regulations 25 to 27 of the *Petroleum (Submerged Lands) Pipelines Regulations 2001*, ModuSpec concluded that:[15]

> *Most of the information required for a description of the Pipeline Management System is not provided. The following aspects are omitted:*
>
> - *Risk of significant pipeline events – This information relates to the incomplete identification of threats and that hazardous events have not been identified in accordance with AS2885.1;*
> - *The measures used to reduce risks to ALARP – These relate to fact that the identified threats have not been categorised in accordance with AS2885.1;*
> - *The management arrangements – This omission relates to the fact that risk management has not been carried out in accordance with AS2885.1.*

1.58 The 2007 ModuSpec Gap Analysis report notes under 'Corrosion' that:

> *The European Gas Pipeline Incident Data Group identifies corrosion as the third highest cause of gas leakage. [Further, while the QCL report had assessed external corrosion] the QCL methodology states that probability of failure in this area is based on the inspection data of anode wastage and CP reading. AS2885.1 lists a number of causes of external corrosion, the implication being that these causes should be considered. There is no evidence that this has been carried out.*

1.59 ModuSpec's recommended way forward is to review threats, reassess pipeline risks for each pipeline in accordance with AS2885 and produce a:

> *...Pipeline Management Plan for the whole network including:*
>
> - *Risk of significant pipeline events and other risks to the integrity of the pipeline;*
> - *Measures to reduce risks to ALARP;*
> - *Arrangements for monitoring, auditing and review;*
> - *Review of the Forward Action Plan.*

15 Although this investigation focuses on facilities and pipelines located on Varanus Island that are licensed under the WA PPA, documents, information and guidance or advice received by Apache relating to any of its Varanus Island Hub operations (which includes facilities and pipelines regulated under the WA PPA, WA PSLA and Commonwealth OPGGSA) are relevant to this investigation due to the interconnected nature of the operations.

2007 – Apache – Onshore pipeline inspection workbook

1.60 A September 2007 Apache 'Onshore Pipeline Inspection workbook' lists the onshore pipeline survey history for the 12 inch SGL since installed in 1993 (sic). The table below indicates that while some basic checking was carried out in the majority of years, there were no checks at all in 1995, 1998, 2002 and 2003.

Figure 5: Onshore pipeline survey history

Year	Pipeline Surveillance	Corrosion Control Facilities Inspection
1993	X	X
1994		X
1995		
1996	X	X
1997	X	X
1998		
1999	X	X
2000	X	X
2001	X	X
2002		
2003		
2004	X	X
2005		X

1.61 In addition, a section of the report assessing the visual assessment of the pipeline stated that the onshore/offshore tie-in point, the isolation flange and the pipeline coating were not seen as they were completely buried, and that the buried section was weight-coated, making the anti-corrosion coating inaccessible for visual assessment.

2008 – Apache – Integrity management personnel and competencies description

1.62 This Apache document was issued on 24 January 2008. It includes an impressive list of roles and responsibilities related to integrity management, including for pipelines. There is substantial similarity between these and the 2000 'Production Facilities Integrity Corrosion Management Strategy' document cited above. The 2008 document also stresses the importance of contractor competency and notes that 'Inspection and NDT is a critical part of corrosion and integrity management'.

2008 – Auscor Pty Ltd – Apache Energy 12 & 16 inch Sales Gas Lines onshore section cathodic protection annual survey 2007

1.63 This March 2008 report by Auscor Pty Ltd only included the mainland onshore 12 & 16 inch SGLs from KP0 to KP31.3. It stated that the pipelines are fully protected over all sections with CP off potentials very uniform and averaging -1.050V. The offshore pipelines at KP0 are fully protected (average -1.12V) with no significant change from previous levels. Since the majority of sacrificial anodes were found to be depleted and hence disconnected, an impressed current CP system located at the CS1 inlet station was proposed.

Safety cases and validations prepared for the regulator

1.64 The initial requirement for a 'safety case' in relation to the Varanus Island facility was for the 16 inch SGL under a PL12 licence variation gazetted in September 1998.[16] Apache developed an in house safety case covering, amongst other things, the 12 inch and 16 inch SGLs in 1999, and later the first Varanus Island Hub safety case which was formally accepted by DMPR (the WA regulating Department pre-DOIR) on 22 July 2002 . This safety case addressed the operation of the facilities on Varanus Island and the associated offshore facilities. It included the complex processing plant on the island and the pipelines, both onshore and subsea covered in the licences held by Apache in relation to all Varanus Island operations. The area critical to this incident was the beach crossing of six pipelines (including the 12 inch and 16 inch SGLs), three import pipelines and three export pipelines (two of which were import and export oil lines) in the transitional zone between the land and sea environment.

The July 2002 Varanus Island Hub Safety Case

1.65 The Formal Safety Assessment (FSA) review for this safety case was commenced in December 2001 and completed in February 2002. The FSA included a section on the 12 and 16 inch SGLs dated 4 April 2001. This referenced the risk assessments carried out by

16 The requirement for a safety case in Commonwealth waters and under Commonwealth regulation dated from 1996.

Stratex in June 1998 conducted prior to the installation of the 16 inch SGL. Listed threats included corrosion. It also stated that:

> *The two SGLs only form a part of the total pipeline system connected to VI. Therefore it is a conservative conclusion to state that the SGLs contribute less than 0.25% of the overall risk to personnel on VI.*[17]

1.66 In relation to the offshore submerged SGLs, the document focus was the 16 inch SGL and reference was made to external corrosion being addressed by external corrosion coating and sacrificial anodes 'inspected annually for offshore sections and every three years for the onshore sections of the pipelines'. For the onshore pipelines (from the pig launchers on Varanus Island to the submerged point of pipelines) corrosion was not cited as a risk or hazard.

1.67 The FSA included an Apache document prepared by International Risk Consultants dated 6 July 2001 and titled Varanus Island Formal Safety Assessment Attached Report. This noted that while offshore pipelines are considered only up to 500 m offshore Varanus Island, 'the entire pipeline inventory is included to provide a more realistic release model', and that high pressure jet gas releases are likely to be rapidly ignited. The Harriet gas import pipeline, Campbell/Sinbad import pipeline[18], and Sales Gas pipeline (sic) and header[19] were each assessed with corrosion as having a potential to cause a jet fire. The Sales Gas assessment noted that there could be fatality on HJV plant and on ESJV plant if jet fire were oriented towards it. For the first two pipelines it is noted that the 'area around onshore section of pipeline is not normally manned' (ie the beach crossing) and for the SGL 'low manning levels and diversity of escape routes from open plant' was noted. All were screened as 'A' major accident events with severity assessed as 'major', likelihood 'unlikely' and risk 'marginal'. Issues with relatively close pipeline spacing potentially contributing to an escalation of MAE were not cited. Corrosion mitigation measures were also lacking in documentation in the 2002 safety case material we have been able to access.

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17 At about the time of the 3 June 2008 incident we calculated that the two SGLs contributed 1,540 tonnes of about 4,100 tonnes of hydrocarbons or about 37.5 per cent of the hub's hydrocarbon inventory.

18 Later in the document this pipeline was termed a 'flowline'.

19 By 2002 both Sales Gas Pipelines, the 12 inch SGL and the 16 inch SGL, were operating and hence both should have been listed and assessed with the plural used here.

The July 2007 revision of the Varanus Island Hub Safety Case

1.68 The Varanus Island Hub Safety Case was subject to its first five-yearly update in July 2007 and comprised three key sections: facilities description, safety management system description and formal safety assessment.[20] It was more than 2000 pages in length. The safety case specifically states that 'all facilities within the Varanus Hub have gone through a robust validation process by independent third parties'.

1.69 An overview to the document stated, inter alia, that:

> *Formal Safety Assessments have been performed which:*
>
> - *identify all hazards and associated credible accident events concerned with the operation of the Varanus hub facilities;...*
> - *demonstrate that the risks associated with major accident events are appropriately managed and reduced to ALARP. ...*
> - *ensure compliance with the West Australian Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) (MoSOF) Regulations 2007 and the Commonwealth Petroleum (Submerged Lands) (MoSOF) Regulations 1996;*
> - *ensure alignment with the National Offshore Petroleum Safety Authority (NOPSA) Safety Case Guidelines ... [and]*
> - *update ... the risk assessment models to include the latest data sets.*[21]

1.70 In the safety management system (SMS) it was stated that:

> *This document describes how occupational health and safety are managed by Apache Energy Limited (Apache) in a style promoted by a philosophy of self-regulation and continuous improvement.*

1.71 The document structure in Apache's SMS appears to place Apache's core values and mission statement in a hierarchy above all else. Safety and health policy, environment policy and integrity policy are at the next level in the hierarchy. External requirements, such as laws and standards, are shown off to one side outside the document

20 The revised safety case was accepted by NOPSA in relation to the offshore elements on 31 October 2007 and by DOIR in relation to Varanus Island itself on 6 December 2007.

21 Although this investigation focuses on facilities and pipelines located on Varanus Island that are licensed under the WA PPA, documents, information and guidance or advice received by Apache relating to any of its Varanus Island Hub operations (which includes facilities and pipelines regulated under the WA PPA, WA PSLA and Commonwealth OPGGSA) are relevant to this investigation due to the interconnected nature of the operations.

structure hierarchy and therefore do not appear to have the same status in terms of prioritisation as Apache's internal policies. This could suggest a lack of integration of external material into Apache systems, and could imply the company treats the SMS in the same compliance-focussed manner noted above as appearing on the Apache website.

1.72 Major Accident Events (MAEs), defined as 'any event arising from a work activity involving death of two or more persons engaged in a Varanus Hub operation', were considered discretely in the FSA. Forty-two MAEs were listed for Varanus Island including hydrocarbon gas release from processing plant or pipelines. The total hydrocarbon inventory associated with Varanus Island in the FSA was stated as 4,100 tonnes, of which the connected offshore pipelines and flowlines totalled 3,900 tonnes. The 12 inch SGL inventory was stated as 560 tonnes. On Varanus Island, the total leak frequency was quantified as 5.9 per year with an average ignition probability of 0.051 and a total ignited event frequency of 0.058 per year.

1.73 Identified hazards were screened for the credible risk of multiple fatalities. Gas release from processing plant or pipelines was identified as part of a credible MAE description. This was analysed as having the potential for immediate fatalities with a large gas jet fire,[22] a flash fire or an explosion. The consequences from a release were said to have had the potential for escalation if atmospheric conditions were suitable, including the spread of the event to other hydrocarbon inventories. The consequences also had the potential for escalation because of compromised escape or rescue opportunities but: 'Personnel who survive an initial fire/explosion event are expected to escape safely prior to escalation, which is conservatively estimated to occur after five minutes of jet fire impingement'.[23]

22 The document stated that: 'Jet fires are high momentum burning jets of gas and/or atomised liquid. They result from ignited gas and two-phase releases, with the momentum provided by the pressure driving these releases. ... Jet fires are very destructive over a large area as they produce high levels of thermal radiation. Furthermore, their destructive consequences include considerable convective heating and erosion when the flame impinges on equipment and structures. This can potentially enable the fire to escalate to surrounding hydrocarbon inventories.'

23 A table of jet fire characteristics for significant Varanus Island process units assuming a 100 mm hole includes the 12 inch SGL with an initial flame length of 122 m and still being 119 m after five minutes. The Sinbad/Campbell 12 inch line which ruptured next on 3 June is assessed similarly (127 m/113 m), while unsurprisingly the 16 inch SGL with higher pressure and more inventory is more (134 m/133 m) and the 6 inch Harriet Gas Flow Line less (127 m initially and 37 m after five minutes).

1.74 The FSA also identifies safety critical items (SCIs) defined as:

> *Parts of an installation and such of its plant (including computer programmes) or any part thereof, the failure of which could cause or contribute substantially to; or a purpose of which is to prevent or limit the effect of a major accident.*

1.75 The SCI hierarchy is described as:

- inherent safety features that eliminate or minimise the potential for a MAE, e.g. structural integrity;
- preventative measures that prevent the occurrence of MAEs, e.g. process hydrocarbon containment systems;
- detection and control systems that influence the scale, intensity and duration of an initial event and limit escalation, e.g. emergency shutdown (ESD); and
- mitigation and evacuation systems to protect personnel from both the initial and escalating events, e.g. escape routes.

1.76 Procedural-based safety critical systems were addressed by the SMS in another part of the safety case. Each system had its own performance standards, which were assured by defined regular audits and reviews of the SMS. The safety critical systems included:

- Competency management
- Integrity management
- Operating procedures (including Permit to Work)
- Emergency response.

1.77 Apache's revised safety case identified the risk of a corrosion initiated rupture of a SGL leading to a jet fire and escalating to adjacent hydrocarbon inventories. Though assessed as 'unlikely' the sales gas headers and pipelines were considered as presenting a 'marginal' but 'credible' risk of multiple fatalities. One of the potential causes of a hazard event from the SGLs was corrosion. The potential consequences identified included explosion from an unconfined vapour cloud, gas ingress or migration to other areas of the facilities, and a jet fire with 'Fatality on HJV plant and on ESJV plant if the jet fire were oriented towards it.' The summary of MAE analysis also included:

> *Gas release from processing plant or pipelines. Potential for large jet fire and/or flash fire explosion. Could result in local immediate fatalities and has the potential for escalation if atmospheric conditions are suitable. There is potential for escalation to other hydrocarbon inventories. High pressure … would lead to a significant release in a short time period.*

1.78 Both integrity management and corrosion monitoring were relevant safety critical systems assessed as able to reduce the incident potential. A consolidation of the safety critical systems was used to develop a hierarchy of safety critical items in the safety case, in which hydrocarbon containment in pipelines and risers came third in the critical hierarchy, with a safety goal expectation of 'inherent safety'.

The 2006–2007 PL12 licence renewal Lloyd's validation process

1.79 In 2006, Apache engaged Lloyd's Register to independently validate the whole plant and facilities of the Varanus Island operations covered by Pipeline Licence PL12 and its variations. This validation was required by the regulator for the purpose of the PL12 renewal. The PL12 licence was originally issued in May 1985 and had a term of 21 years. This included the small section of the 12 inch SGL from the island HJV plant across the beach where the 3 June 2008 ruptures occurred.

1.80 Apache initially provided DOIR with a copy of what amounted to Lloyd's scoping plan for the proposed validation review and on this basis, sought a 21 year extension of the PL12 licence covering most of Varanus Island. Under its service contract, DOIR sought advice from NOPSA. On 21 June 2006, NOPSA advised DOIR that the renewal should not be granted at that time. NOPSA indicated that:

- NOPSA recommended withholding the renewal pending provision of the basis for that statement from the preliminary review, or until the full validation report became available.
- The scope of the validation report encompassed in the report's terms of reference should be broadened to cover more safety-critical areas.
- The pipeline licence had required a formal safety management system since variation 4/94-5; and this requirement had become a subset to a more broad ranging requirement for safety cases since variation 9P/97-8. NOPSA advised that there should be a demonstration that the safety case addressed all the plant and equipment within the PL12 boundary.

1.81 On 7 July 2006, DOIR wrote to Apache providing comments on their licence renewal application that reflected NOPSA's advice. On 6 August 2006, Apache provided DOIR with an updated and broadened validation scoping summary report. On 28 August 2006, Apache again wrote to DOIR with an updated validation plan and details to support the expertise of their selected third party validator (i.e. Lloyd's Register). A timetable was included with the final validation report to be prepared in November 2006.[24] Lloyd's undertook an extensive validation and verification process[25] between May 2006 and April 2007 which included document reviews, interviews and inspections at both the Perth head office and at Varanus Island, followed by a number of workshops.

1.82 The Stage 1 'Integrity Audit' report was dated 31 May 2006[26] and for Stage 3 there were two 'Process Integrity Review' reports dated 30 June 2006 and 21 August 2006, both within the timetable. Apache placed all three documents on its website with the latter two marked 'draft for comment'.[27] There was also a third Stage 3 'Process Integrity Review' report from the period 28 September to 2 October 2006 dated 20 December 2006 and an 'SMS Audit' report undertaken from 6 September 2006 to 14 October 2006 dated 26 November 2006 that were not placed on Apache's website. Apache did place Lloyd's 'PL12 Validation Summary Report May 2006–April 2007' on its website. The date of this summary report is 10 May 2007, well beyond the November 2006 timetable anticipated in August.

1.83 Soon after it was completed, the 16 page 'Validation Summary Report' was provided by Apache to DOIR[28]. This summary report contained a one-page 'Executive Summary' which included a statement that, on 5 January 2006 DOIR had advised Apache and its joint venture (JV) partners that for renewal of the PL12 Varanus Island Pipeline Licence, the Apache JV: 'are required to demonstrate how the whole facility complies with current standards and 'Best Practice' and validate the whole plant and facilities of the Varanus

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24 As at 8 August 2006 the Validation Plan included: 12-24 May 2006 Mechanical Integrity Audit (Stage 1), 25–26 May 2006 Validation Plan Preparation (Stage 2), 29 May–30 September 2006 Detailed Process Integrity Review (Stage 3), 1–31 October 2006 SMS Assessment and IMS Validation (Stage 4), and 1–10 November 2006 Validation Report Preparation (Stage 5).

25 Lloyd's Register states in its 'Apache Process Integrity Review' report dated 20 December 2006 that: 'Validation is the process of evaluating a system or component to determine whether the products of a given development phase satisfy the conditions imposed at the start of that phase. Verification involves completeness and consistency checks and examining for technical correctness in other words confirmation by examination and provision of objective evidence that specified requirements have been fulfilled'.

26 On this Lloyd's stated that 'Based on a preliminary review from initial information gathering and gap analysis, the operation was considered to be covered by a comprehensive integrity management system, sufficient to validate operation for approval for pipeline licence revalidation for the next 21 years'. Despite the caveats, the inspectors' view is that this appears to go beyond what the evidence can sustain.

27 Apache's Australian website, including the Lloyd's documents, was removed in April 2009.

28 The earlier Lloyd's Register stage reports were not provided to DOIR or sought by them.

Island covered by PL12 as fit for purpose for the next 21 years'. The Lloyd's Register Executive Summary therefore notes up-front the onus that is on Apache and its JV partners. Lloyd's Register further states that:

> *...the purpose of this validation summary report is to outline the process, key findings and recommendations to ensure safety of the operational phase and technical integrity for ongoing operations of the Varanus Island plant and facilities covered by PL12 as fit for purpose for the next 21 years.*

1.84 Lloyd's Register's Executive Summary then states that:

> *Key findings are summarised as follows:*
>
> - *No impediment to continued safe operations or compliance with PL12 requirements was identified.*
> - *Vessels under the PL12 licence which have exceeded their design life or will expire during the revalidated operating period require remaining life assessments.*
> - *Provisions were found to be in place with continuous improvement processes to ensure safety of the operational phase and technical integrity for ongoing operations of the Varanus Island whole plant and facilities covered by the PL12 as fit for purpose for the next 21 years.*
> - *The Safety Management System (SMS) is comprehensive and integrated ... [but] Organisational changes and staffing provisions may adversely impact on the ability to optimally operate and maintain plant and facilities covered by PL12.*
> - *A number of workshops were convened in March and April 2007 to review the recommendations and suggestions for improvement identified during the validation exercise and a Validation Action Plan developed to address requirements.*

1.85 The body of the Validation Summary Report includes more detail on the two Lloyd's recommendations:

> *The following recommendations are required to be implemented to ensure that the provisions of PL12 are not negated, potentially resulting in the withdrawal of the current operating permit by the DOIR.*
>
> - *It was noted that some of the vessels under the PL12 licence have exceeded their design life. Hence in order to re-certify the vessels it is recommended that Apache does remaining life assessments for all aging vessels and vessels that will expire during the re-validated period as recommended by AS3788 including the following inspections/ testing as minimum to ensure suitability for continuation of service...*

- *It was observed that manning levels, at Apache, in various disciplines, are low with key competencies contracted out or residing with specific individuals. In addition, due to aging of the workforce and natural movement of personnel in the industry, key critical knowledge areas may be significantly impaired in the short term. Apache should perform studies of tasks required to be done simultaneously and assess adequacy, relative to the staffing and competency levels likely to be present on the facility. Consideration should be given to fatigue, workload, stress on the ability of the person to identify and diagnose problems during management and participation in emergency response.*

1.86 The two recommendations were significant, especially if the vessel ageing issue is taken to include pipelines involved in containment.[29] The report concludes that:

> *Numerous suggestions for improvement were also made to assist in optimising integrity management practices and furthering attainment of 'best practice'. Non implementation of suggestions should not affect the operating licence and are listed in the Validation Action Plan.*

1.87 The Validation Summary Report states that Stage 3 of the validation included 'Comprehensive facilities and equipment integrity review all import and export pipelines, flowlines and onshore pipelines within PL12' including the 12 inch SGL and 'Review of pipeline management plans'. The report also clarifies that standards and codes used in the initial PL12 design were used as the basis for requirements and guidance and:

> *It is not good practice to use an indiscriminate mix of codes or use a different code for a particular problem simply because its requirements are less onerous. ... [but] Due to the age of elements of the facility many of the initial design codes were found to have been superseded and/or revised, in these instances professional judgment was applied to considerations of adequacy and/or fitness for purpose.*

1.88 There are some important safety suggestions among the Lloyd's reports that Apache had placed on its website. Suggestion 8 considered broadening the scope of the safety critical element list to cover elements that were critical to production or environmental conditions. Suggestions 9 to 11 considered the development of performance standards of safety critical elements, their benefits in setting the frequency of inspections and maintenance and

29 Appendix III to the 21 August 2006 Stage 3 report in which the recommendation is made includes 'Subsea Pipelines, Flowlines and Onshore Pipelines' and the 12 inch SGL is listed.

implementing a process for timely reviews of inspection frequencies. Suggestion 13 referred to 'closing the loop' by providing feedback to the initiators of cancelled corrective work orders to ensure that all potential risks were understood. Suggestion 16 referred to the requirements for close-out of anomalies, who should be involved and how. Suggestion 17 referred to arrangements for monitoring and supervising contractors. Suggestion 18 referred to training of core personnel with respect to contractor management.

1.89 Among the reports there is also some important technical information potentially relevant to the 3 June 2008 incident and the role of cathodic protection using sacrificial anodes to protect the subsea pipeline and the shore crossing section.

1.90 Lloyd's also cite AS2832.3 and state that:

> *It is required to maintain a potential on all parts of immersed ferrous structures equal to, or more negative than, -800mV, but not more negative than -1150mV with respect to a silver/silver chloride reference electrode. A potential that is more negative than -1150mV causes the structure to be over protected, which in turn can cause accelerated disbondment of the coating.*

1.91 The Lloyd's 30 May 2006 report on the Apache website also noted that KPI screens had been set up to highlight anomalies and were monitored on a daily basis by specific personnel on Varanus Island and at the field based laboratory on Stag.

1.92 One of the Lloyd's reports that Apache did not place on its website, the third and final Stage 3 'Process Integrity Review' report dated 20 December 2006, an important validation finding referred to the management of modifications and changes. It recognises the importance of change management in organisational matters and notes that the current Apache system does not meet this requirement. The report stated that:

> *NOPSA suggests in their guidance on Safety Case Development that historically, the Safety Case has taken an engineering systems approach to safety. This perspective emphasises the inter-linkages between various items of engineering hardware and the management systems ... The facilities covered by PL12 are considered to be well managed at this level. A broader system view includes consideration of the people collectively - in terms of an organisation. ... The current change management process operated by Apache while suitable for technical change management does not address this broader business management requirement.*

1.93 This report also has an extensive Integrity Management Review Checklist comprising 96 sub-elements with Apache assessed as meeting 81 of them including:

- defining measurable performance targets which Apache defines as ‘Lowest possible cost, maximising production availability’;
- documenting an integrity management strategy on which Lloyd’s states ‘From an interview and review of documentation, the integrity management strategy appears to be regulatory and code compliance’; and
- weighting risk assessment for integrity confidence where Lloyd’s states ‘failure frequencies are generic industry specific and have not been adjusted specifically to operational experience with PL12 facilities… . In general integrity confidence appears to be based on code compliance and operation of facilities within the degradation tolerances of internationally recognised codes’.

1.94 Those not met include: not clearly stating what is within integrity scope, including pipelines although the report notes ‘a verification scheme is under development’; variable performance on integrity reports including relevant data; and issues with roles and responsibilities.

1.95 The body of the 20 December 2006 report states that:

> *Core manning on Varanus Island was identified to be at minimum and no apparent redundancy or duplication of function. This observation implies that specific skill sets are only resident in specific individuals. … Numerous previous reports were identified from audits, inspections, tests and studies with cumulative actions often hidden in the text of reports. Numerous systems are in place to deal with these … [but] Demonstration of close-out, i.e. acceptance or corrective action, was often difficult to identify. This may be due to critical manning levels, reliance on individual competencies, movement of personnel and/or competing priorities. Apache should periodically extract the existing medium and long term integrity management strategies from current maintenance management system and action plans, perform a gap analysis and review prioritisation and resource allocation vs strategic operation life expectancy plan.*

1.96 Lloyd’s Register issued a statement on 14 August 2008 in relation to the gas explosion. The statement indciated that Lloyd’s had conducted a limited verification of Apache’s operations and had:

> *…not contributed to any physical inspection or maintenance-related services to the pipeline or the facility in question. The scope of our report did not in any way guarantee the quality of the ongoing maintenance and safety systems of the facility.*

1.97 The Lloyd's Register statement appear inconsistent with the May 2007 Validation Summary Report.[30] For example, the report records many examples of physical examination of facilities on Varanus Island when the Lloyd's review team visited the island on at least four occasions.

The 2008 Pipeline Management Plan and Pipeline Safety Management Plan

1.98 During 2007, Apache developed a comprehensive Operational Pipeline Management Plan (PMP), as required under the WA PSLA (as well as the OPGGSA). This incorporated legislated requirements for a Pipeline Safety Management Plan (PSMP). The PMP covered all offshore pipelines operated by Apache as well as those pipelines on Varanus Island.[31] The PMP stated that for practical purposes, the assessment terminated at the isolation valves at the end of each pipeline. This meant that the PMP covered the 12 inch SGL for its full length from onshore Varanus Island to CS1 on the mainland at the DBNGP through multiple jurisdictional boundaries. The plan was created to demonstrate integrity assurance, and the elimination or reduction of risks to personnel, the public and the environment to ALARP levels.

1.99 While the PMP (and PSMP) is not explicitly required under the PPA or PL12 for Varanus Island, the licence condition pertaining to the existence of a 'safety case' describes these characteristics in comparable terms to the characteristics of the PSMP. In addition, the integrated nature of the Varanus Hub operations were such that the 12 inch SGL could not easily be considered according to legislative or regulatory boundaries as there was no isolation valve or equivalent in place at these boundaries. In order to adequately consider the safety and integrity of one part of the pipeline, therefore, it is reasonable to consider those parts that are adjacent to the jurisdictional boundary as well as other pipelines (and unlicensed flowlines) in close proximity. Likewise, considerations of safety for a pipeline under the PPA/PL12 relies on considerations of safety for that pipeline under other legislation.

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30 Lloyd's Register appeared to draw and rely upon a significant difference between the terms 'examination' and 'inspection' and between 'guarantee' and 'assurance'.

31 Although this investigation focuses on facilities and pipelines located on Varanus Island that are licensed under the WA PPA, documents, information and guidance or advice received by Apache relating to any of its Varanus Island Hub operations (which includes facilities and pipelines regulated under the WA PPA, WA PSLA and Comonwealth OPGGSA) are relevant to this investigation due to the interconnected nature of the operations.

1.100 Apache’s safety policy, as stated in the PMP, included that:

> *AEL recognise that management has the ultimate responsibility for ensuring that resources and systems are in place to ensure safe and healthy practices … Providing safety and health leadership through the allocation of clear responsibilities with the respective personnel held accountable; … Pro-actively managing all aspects of Safety and Health in all of AEL’s activities; … Being prepared to manage all foreseeable events through contingency and emergency planning; and Continuous improvement through regular audit and review.*

1.101 The safety goals for the assessment were prioritised as:

- Eliminate or minimise the hazards
- Prevent realisation of the hazard
- Prevent escalation of an accident event
- Minimise exposure of personnel to hazards
- Ensure personnel can reach safety in any credible accident event.

1.102 The PMP Formal Safety Assessment and Risk Summary was prepared for Apache by Ionik Consulting with Apache’s active input. The plan considered pipelines in defined onshore, shore crossing and offshore sections and also considered risks to safety, environment, reputation, and financial cost of repair (but not total associated business cost or societal economic losses). A HAZID[32] workshop was conducted by Ionik and Apache staff participated in the assessment of hazards as a part of the PMP development.

1.103 The risk assessment for the 12 inch SGL for the shore crossings considered the shore crossing for Varanus Island and the mainland together, despite the different environments at the two shore crossings. The failure of an adjacent pipeline at the beach approach was recognised and assessed as a risk. The initiating causes of a major hazard considered were rupture of an adjacent pipeline and a subsequent pool fire. A jet fire, such as ensued from the ruptured 12 inch SGL, was not contemplated although possible ‘escalation’ was noted.

1.104 The plan documented that a physical preventive factor was the ‘minimum separation’ between pipelines. The unburied 16 inch SGL was designed to be 9 m from the 12 inch SGL on the beach crossing and offshore. In fact, while it was close to 9 m from the 12 inch SGL at the beach crossing, it was only 6 m from the pipeline

32 A Hazard Identification Study or HAZID is a tool for hazard analysis, normally used early in a project.

immediately adjacent to it. The 12 inch SGL was only 226 mm[33] from the Campbell/Sinbad/Linda 12 inch import pipeline immediately adjacent to it.

1.105 The initial rupture and fire of the 12 inch SGL on 3 June 2008 caused the almost simultaneous rupture of the adjacent Campbell/Sinbad/Linda 12 inch gas pipeline. The separation between the pipelines did not provide a preventive barrier, and did not prevent a pool or jet fire from impinging on an adjacent pipeline and subsequently on the two other gas pipelines immediately adjacent to the HJV plant.

1.106 Two procedural preventive factors were documented: inspection, testing and monitoring of the adjacent pipeline to reduce the likelihood of its rupture; and emergency shutdown of the ruptured pipe to reduce the quantity of hydrocarbon released from the rupture. Where the beach crossing is concerned, the latter is not a valid preventative factor. The isolation valve is at the plant end of the crossing and there is no means of isolating the beach crossing from the total inventory of gas in the 100km pipeline. The 12 inch SGL therefore released approximately 400 tonnes of gas from the rupture. Similarly, although pressure in the 100km long 16 inch SGL had been reduced by continued flow into the DBNGP, a significant inventory of about 600 tonnes of gas was released and contributed to the fires when the 16 inch SGL ruptured approximately an hour after the 12 inch SGL rupture.

1.107 The plan assessed external corrosion as a risk for beach crossings on the mainland and Varanus Island similarly. The potential causes of rupture considered for shore crossings were the breakdown of external corrosion coating and the failure of the CP system. The physical preventive measures considered were the CP system and the anti-corrosion coating. The plan did not recognise, however that a CP system based on subsea sacrificial anodes would not provide consistent protection for a shallow buried pipe in a shore zone subject to variable wetting and drying in sandy soil should the corrosion coating fail.

1.108 The procedural preventive measures were stated to include the use of remotely operated submersible vehicles for inspection and intelligent pigging of the pipe. But clearly submersible vehicles do not work on a beach and no intelligent pigs were run along the 12 inch SGL prior to the 3 June 2008 incident.

33 This was measured from bare pipe to bare pipe or 167 mm measured between the outer coatings and reported by DOIR/NOPSA in the 7 October 2008 investigation report.

1.109 Overall, the formal safety assessment considered the risk as no more than one to ten events per 100,000 years.[34] This low risk level was arrived at largely as a consequence of accepting preventative and mitigating factors that were not applicable at the Varanus Island shore crossing. This overly positive risk assessment failed to recognise that:

- the spacing between pipes increased risk;
- there had been no intelligent pigging on some of the pipelines;
- cathodic protection at the shore crossing was an extension of the subsea system and unlikely to provide effective protection in the onshore wet/dry zone;
- disbonding of the anti-corrosion coating could occur or could already be present; and
- isolation from pipeline gas inventory was based on a shut down valvue that, given its location, could not do this.

1.110 When initially submitted in February 2008, Apache's PMP was not immediately accepted by NOPSA.[35] NOPSA provided detailed comments to Apache noting in particular that there was

> *...no comprehensive demonstration of the effectiveness of the risk mitigation measures implemented to reduce the risks to ALARP... AEL should insert appropriate information in the PMP to satisfy this requirement.*

1.111 Apache's response to this comment was to include a table listing all safety risk reduction measures including anti-corrosion coating, and the corresponding effectiveness assurance process for the pipelines covered in the PMP. This excluded intelligent pigging for the 12 inch SGL.[36] Apache also noted in the PMP that:

> *...the corrosion management system is a 'live' process for all pipelines, continually evolving as operating conditions change and corrosion mitigation monitoring data is assessed. The system is evaluated and managed in the production reporting system, providing real-time performance review capability. External corrosion of submersed and buried pipelines is mitigated by high quality coating systems supplemented by cathodic protection.*

34 Even when applied correctly, Quantitative Risk Assessment – or QRA – such as this is considered by other duty of care regulators only as a means to identify risk, not a means to excuse a failure to reduce the risk further particularly if a standard industry practice method of risk reduction is available.

35 NOPSA assessed those pipelines that were licensed under the WA PSLA where NOPSA had conferred powers, which covered the offshore sections of 14 of the 41 lines contained in the OPMP.

36 Apache also included a summary "bow-tie" style diagram for each licensed pipeline to demonstrate barriers and mitigation measures in place to reduce risk items to ALARP.

1.112 The PMP/PSMP accepted by NOPSA and subsequently by DOIR in March 2008 continued to assess the risk at the shore crossing as 'low'. The HAZID process undertaken as part of the formal safety assessment did not make it clear that serious pipeline hazards and risks were not being properly managed and, as a result, the risks were seriously underestimated and not reduced to ALARP.

Regulator audits and recommendations

1.113 Safety audits of Varanus Island were conducted regularly by DOIR until NOPSA's formation in 2005. NOPSA then conducted five audits on Varanus Island between March 2005 and March 2008 in accordance with its service contract with DOIR prior to the incident. Findings of these audits were transmitted to Apache in the form of draft close-out reports provided at the audit site before departing, as well as the final report which was sent at a later date. While there were many positive findings in these reports, they also include consistent negative findings, deficiencies and non-conformities. These include a lack of: performance standards and indicators, documented procedures and audit or review associated with some management systems, and also some systems becoming excessively behind/backlogged.

DOIR audits

1.114 Of DOIR's safety audits at Varanus Island, a February 2001 audit found issues with lack of specialist corrosion staffing and that:

> *One repair of note concerns the replacement of a section of pipework on Harriet Alpha. The pipe contained a welded joint with external corrosion. The wall thickness had reduced from approximately 5mm to 0.5mm. Importantly, the defective area, which is normally inaccessible, was discovered by chance.*

1.115 A March/April 2003 audit stated that the Apache audit protocol failed to ensure that all SMS elements were audited over a period of time and also that contractor management was deficient. A June 2003 audit found that the change management control did not adequately assess for HSE risks and that operational procedures were documented after commissioning. Consequently, DOIR considered there was 'a real level of concern about the systematic management of the knowledge available to run the operation'.

1.116 The last DOIR audit of the Varanus Island operations under Apache's safety case was in May 2004. It included a number of positive observations and found that progress on close-out of previous audit items was 'fair' and that progress was still being made on issues such as Change Management Control. However, 'maintenance was identified as a major issue for improvement.' Assets were beginning to show their age and a specific concern included 'the amount of time spent on corrective rather than preventive maintenance ... Maintenance has a critical role in providing integrity of equipment.'

NOPSA audits

1.117 From 2005, NOPSA's safety audits of the Hub Safety Case, including Varanus Island, addressed key management systems including maintenance management, change management, pipelines safety and integrity management, MAE/alarm management, facility integrity management, critical valve management, emergency shutdown/ blowdown management and programmed audit management. The most significant recurring theme centred on deficiencies in Apache's auditing of its own systems.

- NOPSA's June 2005 (Varanus Hub Offshore) audit found:
  - a 'lack of evidence of comprehensive audits for the maintenance system'; and
  - 'no record of audits of the permit to work system other than on Harriet A'.
- The February 2006 (Varanus Hub Offshore) audit found:
  - 'no identified arrangements for the ongoing monitoring, audit, and review of the pipeline maintenance and integrity management system'; and
  - 'Apache does not have defined arrangements for monitoring, auditing and review of the management of change system (projects)'.
- NOPSA's November 2006 (Varanus Hub Offshore) audit found that:
  - in relation to the facility integrity management system that, whilst an extensive audit and review of the integrity assurance system was currently being carried out by Lloyd's as part of PL12 renewal, no regular audits of the system were being carried out and that the company had no requirement for such audits);
  - there was no evidence of the incident reporting and investigation system/procedure being audited[37].

37 Although this investigation focuses on facilities and pipelines located on Varanus Island that are licensed under the WA PPA, documents, information and guidance or advice received by Apache relating to any of its Varanus Island Hub operations (which includes facilities and pipelines regulated under the WA PPA, WA PSLA and Commonwealth OPGGSA) are relevant to this investigation due to the interconnected nature of the operations.

- Finally, in its May 2007 (Varanus Hub Onshore – service contract) audit, NOPSA concluded with regards to Apache's own audit system that:
  - 'whilst [Apache's] audit [system] contains some systems and procedures there is no comprehensive audit system in place that would ensure systematic audits of all relevant systems and procedures'.

1.118 All these systems are safety-critical in upstream petroleum operations. The fact that concerns were raised across the board should have prompted Apache to identify systemic issues requiring remedial action and timely and complete closing out of findings and recommendations. With particular regard to auditing, NOPSA required Apache '...to develop and implement a comprehensive audit system'.

DOCEP and pipeline integrity reviews

1.119 From 1 July 2005, regulatory safety assurance covering the mainland section of the 12 inch SGL was undertaken by the WA Department of Consumer and Employment Protection (DOCEP) under a service arrangement and then a MOU with DOIR. This portion of the pipeline was regulated under the WA PPA Pipeline Licence PL17. Condition 5(b) of variation 10P/97-8 of PL17 required the pipeline operator to review the pipeline's integrity two years after the initial licence grant and every five years thereafter, and to provide a report from that review to the regulator.

1.120 On 14 September 2006, DOCEP asked Apache to provide a report on its compliance with PL17 and its safety case implementation, and to provide a review and assessment of the onshore sections of the 12 inch and 16 inch SGLs' fitness for service, including the data, information, and methodology that were used. DOCEP also reminded Apache that an operational safety case needed to be submitted and accepted pursuant to the conditions of the licence. However, it advised that a report that covered more than PL17 would be sufficient so long as it adequately covered everything in PL17.

1.121 On 1 May 2007, Apache was advised in writing that the requirement for a recurring integrity review was now considerably overdue. DOCEP formally required the provision of a plan for the review report incorporating the report's terms of reference, proposed methodology and timeframe for the review. On 7 May 2007, Apache responded by saying that the report was being developed and a copy would be sent to both DOCEP and DOIR by the end of the month. On 31 May 2007 Apache provided copies of the 'Sales Gas Pipelines 5-Year Integrity Review' report that had been issued for use on 30 May 2007.

1.122 This review was undertaken for Apache by Subsea Developments (Australasia) Pty Ltd[38] and completed in May 2007. Its stated purpose was 'to provide a summary of the status of the SGLs with respect to their current condition and the activities performed in the ongoing integrity management over the period' and 'includes inspection and corrosion activities performed during the period from 2000 through to December 2006' for the 12 and 16 inch SGLs. The Subsea report notes that 'Apache is selectively using qualitative risk assessments to help establish optimum survey intervals'. It cites the 2004 QCL report and the two April 2007 ModuSpec reports and states, based on the CP and other data reviewed, that 'The SGLs are generally in a good condition based on the monitoring and inspection activities reviewed and summarised in this document'.

1.123 The Subsea report's conclusion is:

> *There are no findings from the integrity management processes performed for the Sales Gas Pipelines that provide any reason for any changes to the ongoing IMR [Inspection Maintenance and Repair] activities that are not already being addressed in the current risk assessments and anomaly tracking and close out practices. The AEL Pipeline Integrity Management process is generally following the requirements of AS2885 and any specifics included in the Pipeline License for the Sales Gas Pipelines.*

1.124 Subsea Developments note that planned Apache activities will include 'Inspection of onshore pipeline, To allow wall thickness monitoring, Every three years, 2007 – UT Inspection'. There is also a diagram that includes intelligent pigging linked to the onshore integrity plan/schedule but it is not clear if this includes the Varanus Island shore crossing or just the mainland.

38 Inspector Agostini declared his interest with Neptune (which owns Subsea) at the outset of our investigation and took no part in the assessment of any material involving Subsea which was left to Inspector Bills.

Foreseeability: conclusions from the documentary analysis

1.125 Apache internal documents prior to the 3 June 2008 incident raised serious issues about a lack of inspection of the 12 inch SGL at the onshore transitional zone. Some point to vulnerabilities in this area with a possible rupture entailing potentially catastrophic MAE effects. Some documents exhibit confusion as to whether the small section of the 12 inch SGL on Varanus Island is covered in the particular studies or assessments. There also seems to be variable technical understanding of cathodic protection efficacy in the zone and any possible interference from adjacent pipelines in a narrow corridor.[39]

1.126 On balance, we believe that Apache was in possession of more than enough material to indicate that a rupture due to external corrosion in the Varanus Island onshore transitional zone was a foreseeable real risk requiring attention. In some reports it was foreseen as a particular hazard. Apache's risk assessments and internal management methodologies and systems, however, failed to adequately consider the Varanus Island shore crossing zone as having a higher risk profile than the subsea pipelines. The evidence for these conclusions includes the following.

1.127 The 1996 Apache 'Statutory Inspection Manual' cited AS2885 in terms of the need for regular inspections and at least yearly potential surveys for onshore pipeline but did not appear to recognise the portion of the 12 inch SGL under PL12 crossing the Varanus Island shore zone.

1.128 The 1997 Ferrum Technology' Cathodic Protection Review' noted that the current requirement for both the 12 inch SGL and the proposed 16 inch SGL 'is very dependent on the moisture content of the soil'. It recognised difficulties and vulnerability associated with where the subsea pipeline connects to the onshore pipeline and the desirability of avoiding any air-to-soil interfaces. It stated that it was not possible to determine the need for an intelligent pig based on CP data and said it would be 'prudent to conduct the pigging survey over the onshore section of the pipeline, especially if this type of data has not been previously obtained'. However, Apache did not act on this recommendation before the explosions more than a decade later.

39 When the Inquiry asked Apache whether the pipelines were treated holistically for CP treatment, Apache replied on 26 March 2009 'No'. An Apache schematic of the 12 inch SGL approved on 27/07/04 and last reviewed on 07/09/07 states that onshore Varanus Island is covered by PL17 and onshore the mainland by PL12 (the reverse is correct). It also states that the 70m onshore Varanus Island section starts at KP69.748 and is buried with no cathodic protection and the offshore section starts seaward of KP69.748 and is concrete coated and has bracelet anode cathodic protection.

1.129 The August 1998 Stratex report identified the importance of inspections in relation to external corrosion at the Varanus Island shore crossing for the 12 inch and soon to be commissioned 16 inch SGLs. The stray current effects and breakdown of coating issues noted with respect to the new 16 inch SGL have more general applicability (eg see Annex 10) and may involve adjacent pipelines however, no reference covering stray current effect or failure of the concrete coating was made regarding the 12 inch SGL at the Varanus Island shore crossing.

1.130 The September 1998 QCL report noted the lack of baseline intelligent pigging data for the 12 inch SGL but that this was not a reason to avoid what it termed 'necessary' pigging in 1999. Importantly, the QCL report identified that a pipeline failure on Varanus Island near the plant or on the mainland could 'endanger life'.[40]

1.131 The February 2000 Apache 'Production Facilities Corrosion Management Strategy' highlighted the threat posed to pipelines by corrosion and noted the benefits of intelligent pigging.

1.132 The April 2000 J P Kenny 'Pipeline Asset Inspection Strategy' referred to the need for annual inspections, with ultrasonic wall thickness testing at least five yearly and at hot spots, and an external coating survey whenever the pipelines were visible.

1.133 The July 2000 QCL compilation of Apache's 'Asset Integrity Management Audits' was also provided to the WA Department and noted that 'a centralised corrosion database does not exist' and 'Asset lives are not calculated at the moment'. Recommendations made by Lloyd's Register to improve safety were downplayed, and there were issues with missing CP data.

1.134 The Varanus Island Hub Safety Case approved by DOIR in July 2002 appears to understate the risk of corrosion at the Varanus Island shore crossing and does not assess issues such as the relatively close pipeline spacing over the shore zone.

1.135 In relation to the 2002 and 2003 Auscor CP surveys, there was no discussion in the reports of any possible dangers of excessively high voltage and no readings for the Varanus Island onshore section for either the 12 or 16 inch pipelines. The Apache Energy 'Onshore Pipeline Inspection Manual' most recently issued for use on 22 March 2006 (first issued mid-1997) states that test results outside the range of -850mV to -1200mV are considered

40 The 1998 QCL report does not assess CP efficacy, such as where disbonding of the anti-corrosion coating may have occurred shielding the pipe from protection, or where CP is intermittent due to varying soil conductivity (e.g. due to tidal effects in sand), or where stray currents or interference may be an issue.

'anomalous' and 'shall be' subject to detailed evaluation.[41] The Auscor mid 2002 and 2003 results include readings (up to -1404mV) above the range stated in the 2006 Apache Manual as 'anomalous' and so 'shall be' subject to evaluation. We have seen no evidence of such further evaluation.

1.136 While the 2004 QCL report did not highlight the problem of inspections under concrete weight coating, it did identify gaps and the absence of objective data relating to the pipelines at the shore crossing and the 'critical' consequences linked to the 'medium' risk of external corrosion at the Varanus Island shore crossing and onshore. Despite the QCL report, other than the Netlink work noted below, little appears to have been done about the lack of data for the shore crossing and onshore section at Varanus Island where, for the rupture zone, the concrete coat and partial burial should have negated the value of a general visual inspection. Unlike in 1998, there was no reference by QCL to intelligent pigging.

1.137 The 2004 Netlink Inspection Services report on the 12 inch SGL found a corroded section of pipe under the anti-corrosion coating and also missing and cracked weight coating at the shore crossing zone in the region where the 12 inch SGL ruptured. Based on the April 2000 J P Kenny document, this exposed pipe and coating should have been further checked for corrosion, properly repaired and the risk of further corrosion assessed. This corrosion should have led Apache to revisit its CP system and be more vigilant in future inspections on Varanus Island.

1.138 The January 2006 annual summary report of inspection and corrosion management activities includes details of intelligent pigging undertaken. No intelligent pigging had been undertaken on the 12 inch SGL.

1.139 The 2006 Apache 'Onshore Pipeline Inspection Manual' is confusing in relation to coverage of the section of the 12 inch SGL that begins at the pig launcher on Varanus Island under the PL12 licence and in relation to the existence of the PL17 licence. However, it emphasises the need for annual pipeline inspections pending more data enabling risk assessments.

1.140 The 2007 ModuSpec report makes a serious criticism that there is no evidence that the causes of external corrosion in the key Australian Standard AS2885.1 had been considered by QCL. This gap may be added to QCL's own 2004 concerns.

41 The 2006 Lloyd's PL12 validation/verification reports cited below stated that potentials more than 1150mV can lead to disbondment of the anti-corrosion coating. Such disbondment can then enable a corrosion cell to be created which can rapidly corrode a pipe.

1.141 Despite some basic pipeline surveillance and/or corrosion control facilities inspection noted in nine years out of 13 in Apache's 'Onshore pipeline inspection workbook' the 2007 Subsea Developments report does not highlight the concerns raised previously by the QCL reports and ModuSpec reports and does not raise the continuing lack of adequate data on the 12 inch SGL at the Varanus Island shore crossing. Its conclusions on the integrity management of the SGLs seem therefore overly positive.

1.142 The revised Varanus Island hub safety case of July 2007 was more complete than the 2002 document and assessed the 12 and 16 inch SGLs as presenting a 'marginal' but 'credible' risk of multiple fatalities based on hazards such as corrosion leading to explosion and jet fire. However, some issues involving pipeline risks were again not documented. Despite identifying that the 12 inch SGL presented an MAE risk potentially involving fatalities and escalation , Apache did not ensure that there was effective integrity management and corrosion control on the section of pipe that ruptured or act to more fully mitigate the risk of escalation from adjacent pipes.

1.143 We consider that the 10 May 2007 Lloyd's Register one page Executive Summary of its 'Validation Summary Report' if considered alone may appear overly positive to a casual reader. However, in the context of the 16 page Validation Summary Report and the more detailed Stage reports, it seems much more reasonable. Lloyd's Register recommendations focus on ageing hydrocarbon containment integrity and issues with low levels of staffing and consultancy. Lloyd's does not appear to have reviewed some of the key consultancy reports cited earlier that could have led to even stronger advice to Apache.

1.144 The 2007–2008 Pipeline Management Plan included substantial sections on hazards and risks prepared with Apache staff by Ionik Consulting. These identified many of the core issues associated with the rupture and its escalation but by not reflecting the reality on the ground and by considering mitigation measures that were not applicable, the PMP seriously underestimated the risk of a credible MAE hazard associated with the SGLs, and what was probably the last opportunity to address this risk properly was lost.

Conclusion

1.145 We found many aspects of Apache's operations and documentation to be commendable. However, statements like those quoted under the chapter heading, the legalistic, self-serving and argumentative tenor of its extended critique of the DOIR/NOPSA Varanus Island investigation report and its similar approach to our inquiries, all suggest that Apache's main concern is one of minimising potential liability. While we understand Apache's concern, this approach is an impediment to addressing the regulatory and operational safety issues relevant not only to Apache, but to the oil and gas and other high hazard industries generally.

1.146 In his review of the information available to Apache for the purposes of this investigation, Professor Rolf Gubner, Chair of Corrosion at Curtin University of Technology in Western Australia, concluded that there were two underlying problems in respect to the integrity management of the pipelines by Apache on Varanus Island:[42]

1. *It can be noted that there seems to be no or little effective communication between the field corrosion technician and the management. Reports produced by either Apache's own technician or hired consultants do not result in any satisfactory reaction to mediate or mitigate corrosion damages. If a trained CP specialist had been asked to analyse the data from Varanus Island, he would have demanded additional data to verify the function of the CP system. Warning flags have been raised since the first CP reports in 1995. It seems like Apache reacted to each report by commissioning another study or to implement new guidelines and procedures on how and what to inspect, but the prescribed work was not performed adequately. The ultra shallow water report by Netlink (2004) had all the indications documented that the CP-system for the shore crossing was not working as planned. If acted upon, the incident could have been avoided.*
2. *The qualification of the contractors and staff on Varanus Island can be questioned. The principles of Cathodic Protection do not seem to be understood by the personnel performing the tests and submitting the reports.*

42 Professor Gubner's full report is at Annex 5 and other key aspects are highlighted in chapter 4.

1.147 Overall, the history of Apache documentation and response indicates that the operator had substantial information that could have enabled it to reduce the risk of rupture of the 12 inch SGL at the Varanus Island shore crossing to ALARP levels through a range of good oilfield practice measures including intelligent pigging. That it chose not to do so may reflect a trade-off between production efficiency on the one hand, and thoroughness in its approach to safety management on the other.

1.148 The documentation indicates that the risk of a major accident event at the beach crossing because of external corrosion to a high pressure gas pipeline was not only foreseeable, but foreseen in a range of documentation. A lack of data and willingness to proactively address the organisational and other issues uncovered through the audits and the Lloyds Register validation, led Apache to miss critical signs that the 12 inch SGL under the PL12 licence issued pursuant to the PPA presented a high and increasing risk which was not being mitigated or managed. Actions and omissions by Apache and some of its contractors increased risk of the incident occurring.

2: Better practice and the evolution of a safety culture

In any beach environment the risk rating must be high since the environment is not stable - wetting/drying, movement and potential salt and corrosion and protection interference [can all contribute to external corrosion].

Oil and Gas Pipeline Integrity Conference, Amsterdam, February 2009

Taking inappropriate risks, not following procedures and a belief that 'productivity is the most important thing in our business' are all indicators of a weak safety culture which invariably negates the benefits that good engineering practices, procedures, training and management systems provide.

US Center for Chemical Process Safety, 2007[43]

From interview and review of documentation the [Apache] integrity management strategy appears to be regulatory and code compliance.

Lloyd's Register Process Integrity Review Report for PL12, 2006

2.1 The information available to Apache through internal and consultants' reports, regulatory documents, and interactions with the regulator made up only part of the information available to Apache to assist it to determine its practices for the safe operation of the 12 inch SGL. Information contained in accident/incident reports,[44] regulators' expertise, standards and expert literature, and thorough industry practices and information sharing is commonly

43 Crowl D (ed.), *Human Factors Methods for Improving Performance in the Process Industries*, Centre for Chemical Process Safety, Wiley-Interscience, 2007, p125.

44 This includes incident/accident reports related to other industries, not just oil and gas. Cf annexes 11, 16 and 17.

used by high reliability organisations (HROs),[45] regulators and industry associations to determine better practice. The industry and expert information regarding pipeline corrosion and good practice in pipeline operations is also an important consideration in determining whether this incident could have been avoided. This chapter will discuss those broader influences that could also have alerted Apache – or indeed the regulators – to the potential for this incident.

2.2 Apache's response to the numerous reports and advice provided to it by experts and regulators, and its receptiveness to information available in the industry is critically important in assessing the operator's ability to prevent a serious safety incident. The determining factors for Apache's receptiveness to these sources of information are reliant on its organisational mindfulness of safety issues, its organisational technical capability and, more generally, its safety culture. These factors are also considered in this chapter, while the regulators' roles, understanding and responsiveness to the information available is then considered in chapter 3.

Accident and incident reports relevant to the petroleum industry

2.3 The dangers of corrosion to pipeline integrity are well known in both the pipeline and oil and gas industries. In the US, for instance, there has reportedly been an average of 52 significant corrosion incidents annually with more than three quarters of onshore incidents being due to external corrosion. Accidents involving corrosion and pipeline explosions with multiple fatalities have been independently investigated by the US National Transportation Safety Board (NTSB) and the Transportation Safety Board (TSB) of Canada, and the results of these investigations are publicly available.[46] In addition, these bodies are well represented in various public and industry forums, thus helping to ensure that lessons learned are effectively communicated to the industry.

2.4 A Canadian incident and investigation in 1997 provides a particularly pertinent example. On 2 December 1997 a rupture and fire occurred at an area of general external corrosion on the TransCanada 914 mm outside diameter natural gas pipeline near Cabri, Saskatchewan. There were six parallel pipelines in the vicinity. About

45 A high reliability organisation is one which has avoided MAEs in an industry where accidents can be expected due to risk factors and complexity. Oil and gas operators should always aim to be high reliability organisations (HROs) as they operate in settings where the potential for error and disaster is ever present and hence the organisation must function reliably.

46 <http://ntsb.gov and http://www.tsb.gc.ca/en/> respectively (see Annex 11).

70 per cent of the wall thickness had been corroded after the pipe coating of asphalt enamel, felt wrap, kraft wrap and an outer wrap had either been damaged or become disbanded. The TSB stated that even a brief interruption in cathodic protection would have allowed corrosion at uncoated locations. Further:

> *since the soil conditions at the rupture site alternated between wet and dry, depending on the season, sections of the pipe that were poorly coated would have experienced variations in corrosion rates and the amount of current required for adequate protection.*

2.5 Many MAEs in the petroleum and chemical industries cannot be explained by the mechanics of the incident alone and organisational factors and safety culture must be considered when seeking a systematic understanding and root causes. Good examples are the US Chemical Safety and Hazard Investigation Board (CSB) report on the 2005 multiple-fatality explosion at the BP Texas City refinery (Annex 11) and the Australian Transport Safety Bureau (ATSB) report on avgas contamination in Mobil's Melbourne refinery that grounded thousands of aircraft across eastern Australia at the beginning of 2000 (Annex 17). There are many other similarly excellent investigations freely available on the web. For such an investigation to be successful it must generally be both independent, to avoid any potential conflict of interest, and 'no-blame' to ensure that the 'stop rule'[47] does not prevent complete analysis of all possible contributing factors.

2.6 Organisational and regulatory factors are also highlighted in major judicial inquiries into accidents such as Lord Cullen's reports and recommendations following the Piper Alpha disaster and Ladbroke Grove collision, and by Justice McInerney's reports and recommendations into the Glenbrook and Waterfall rail accidents in NSW (see Annex 16). There is also a substantial amount of literature on the role of organisational culture in major accidents, including by Professor Andrew Hopkins, who has focussed on oil and gas industry MAEs such as at the ExxonMobil Longford gas plant in 1997 and at the BP Texas City refinery in 2005 (Annex 16).

2.7 In addition to this best practice, the major difficulties we have experienced in our inquiries and investigations since January 2009 because of a lack of appropriate investigation powers and protections, underlines the need for legislative change.

47 See discussion of investigations at Annex 2.

R 1 **We recommend that Western Australia seeks the establishment of a properly resourced independent national safety investigation body to investigate serious offshore oil and gas and onshore petroleum pipeline accidents and incidents. The body should be empowered to compel documents and witnesses and be required to make public a professional systemic no-blame investigation report that is appropriately protected from legal action for the purpose of improving future safety.**

Regulator and technical expertise relating to pipeline and pipeline corrosion at shore crossing areas

2.8 International Regulators' websites hold a large amount of useful information on general matters as well as pipeline corrosion concerns. For example, the US onshore regulator, the Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) has an expert but easily understood paper summarising the basics of corrosion science and pipeline integrity threats and protection (Annex 10). The Irish Government also has valuable information available on the internet, including a safety review of a proposed gas pipeline that includes discussion of specific corrosion control concerns at a shore crossing section (Annex 23).

2.9 The UK HSE produces a range of publications specific to pipelines. For example, on 19 February 2008 the Gas and Pipelines Unit released 'Use of pipeline standards and good practice guidance' that dealt with the:

> *...many well established standards, covering design, operations and maintenance of UK sector major accident hazard pipelines, both onshore and offshore, which can be used to demonstrate that risks are ALARP.*

2.10 This publication notes that other standards may be acceptable 'provided they can show that they achieve equivalent levels of safety' and recommends a gap analysis to confirm this.[48] Further, it notes that:

> *...verification requirements impose a network of interrelated duties. The major accident prevention document required ... may contribute to arguments in the safety case, and where appropriate should be referenced ...For the purposes of the safety case, the ... Regulations deem any part of a pipeline connected to the installation, and associated apparatus or works, located within 500 metres of the installation, to be part of the installation.*

48 HSE, *Assessment Principles for Offshore Safety Cases*, March 2006.

2.11 Similarly, the American document US Code of Regulations for Transportation has a range of natural gas pipeline requirements for corrosion control and integrity management and provide guidance for implementation of an integrity management program.[49]

Standards on pipeline management

2.12 In Australia, NOPSA has indicated that it recognises the Australian Standard *AS 2885: Pipelines – Gas and Liquid Petroleum* as an appropriate standard for pipelines (see Annex 21). The Standard outlines, inter alia, a risk assessment process for managing the safety and integrity of a pipeline over its lifetime, including design, construction, operation and maintenance. Apache references this standard in both its Varanus Island Hub Safety Case and Pipeline Management Plan.

2.13 AS 2885 is largely written with onshore pipelines in mind, with the exception of Part 4 which is specific to offshore (subsea) pipelines. Part 4 of the Standard defines the limits of 'offshore submarine pipeline systems' as up to the extreme high water mark, and then disapplies AS 2885 for offshore sections of a pipeline, referring the reader to Norwegian Standard DNV OS-F101.[50] The superseded 2000 version of DNV OS-F101 specifically excluded the shore crossing area landwards from the low water mark in its section on corrosion protection measures. In this instance, as per the Australian Standard, the exclusion prompted the re-application of AS 2885 for corrosion protection measures for this shore crossing area. However, AS 2885 was not written with the shore crossing area in mind, and the corrosion protection measures mentioned in the Standard may not be ideal for this section of a pipeline route. Fortunately the scope of the current 2007 version of DNV OS-F101 has been expanded to include corrosion protection measures across the entire scope of the Standard,[51] including the shore-crossing area of a pipeline.

2.14 It is common for pipelines to be designed and built according to Standards which are revised multiple times during that pipelines design life. Where such revisions occur, it is not expected that

49 US, Code of Regulations 49, Parts 186 to 199, Revised as of October 1, 2007, Transportation.

50 It states: 'All requirements for offshore submarine pipeline systems with respect to safety, design, materials, fabrication, installation, testing, commissioning, operation, maintenance, requalification and abandonment shall be in accordance with the latest edition of DNV OS-F101. The requirements of AS 2885.1, AS 2885.2, AS 2885.3 and AS 2885.5 are not applicable.'

51 Standards Australia has advised that a revised AS 2885.4 to be released in the near future will be consistent with the DNV Standard.

companies would necessarily outlay significant expense in an effort to comply with each variation from the previous version of the Standard. However, it is industry better practice, and expected by regulators (indeed required under the OPGGSA) that companies revise their practices where a Standard has changed such that the superseded version no longer represents good practice or ALARP. While it appears there has been some inconsistencies in the past relating to coverage of shore crossing areas, keeping abreast of the latest updates of National and International Standards should ensure that industry and regulators remain aware of better practice as it is at that time.

R 2 **We recommend that DMP ensure that there is clarity in its regulation of safety across oil and gas and other high hazard industries in terms of which standards are required to be applied under licences, regulation and legislation and that there is an obligation upon operators to apply the most appropriate standard to reduce risk to ALARP in accordance with good industry practice.**

Information and standards on cathodic protection

2.15 CP is an important corrosion mitigation measure for pipelines[52] but is a tight specialist niche in terms of industry and regulator knowledge. Several specialist CP companies told us that operators and regulators can both lack expertise in CP systems and that simply listing it as being in place is enough for both without consideration (or understanding) of issues such as whether the proposed CP system treats pipes holistically or might face interference from CP systems in adjacent pipes, powerlines or equipment and whether it will be appropriately managed over time.

2.16 The same CP specialists also noted that some companies do not provide technical specifications when they tender for a CP system instead relying on the contractors responding to the tender to design the CP system leading to a lowest cost, but not always optimum, solution. Operators without the technical capability to assess the corrosion risk and to specify the CP system are dependent

52 The Det Norske Veritas (DNV) Recommended Practice DNV-RP-B401 Cathodic Protection Design issued in hardcopy in January 2005 and amended as at April 2008 states (p7) that CP can be defined as 'electrochemical protection by decreasing the corrosion potential to a level at which the corrosion rate of the metal is significantly reduced' (ISO 8044) or 'a technique to reduce corrosion of a metal surface by making that surface the cathode of an electrochemical cell' (NACE RP0176). DNV states that CP 'has a corrosion reducing effect on surfaces intermittently wetted by seawater'.

on the pipeline specialist contractor bidding for the job. In these circumstances, due to commercial pressure, these companies risk ending up with a low cost inadequate or sub-optimal CP system.

2.17 This would appear to be consistent with the specification documents covering the original Varanus Island development where, as we noted in the previous chapter, most issues were specified in detail but the CP systems were covered off with simple statements that CP systems would be installed on both the onshore and offshore sections. In this case it was Apache's predecessor, Hadson, which tendered for the CP system. It is also consistent with Apache's lack of review of the technical basis of the 12 inch SGL CP system installed and the ongoing monitoring and maintenance of the CP systems, where anomalous readings were apparently neither recognised nor investigated.

2.18 There are many excellent texts on CP[53] and much can be learned from reviews and investigations around the world. While operators and regulators should be able to rely on contracted expertise relating to CP, there needs to be a realisation that it is not enough to simply 'tick the box' that CP has been taken care of or take current readings without understanding the implications of anomalies.

Better practice maintenance of pipelines in a shore crossing zone

2.19 In our discussions with various international and national regulators, there were differences of opinion as to the precise risk rating that should be attributed to shore crossings. The MAE potential of the wet/dry splash zones of a pipeline riser[54] is typically recognised and regulated more carefully by offshore safety and integrity regulators than a shore crossing for two reasons:

- The wet/dry zone of a riser is situated directly under a platform with obvious MAE escalation potential; and
- A prevailing assumption that any pipeline crossing a beach would be deeply buried.[55]

53 For example, see M. Parker & E. Peattie, *Pipeline Corrosion and Cathodic Protection,* 3rd edn, Gulf Professional Publishing, 1988; W. Von Baeckmann, *Handbook of Cathodic Corrosion Protection*, 3rd edn, Gulf Professional Publishing, 1997; and J. Riskin, *Electrocorrosion and Protection of Metals*, Elsevier Science, 2008.

54 Ie the section of a pipeline which is above the extreme low tide level and the point at which it connects an offshore platform.

55 Apache's design for its Devil Creek (near Dampier, WA) development shows the pipeline deeply buried at the shore crossing zone.

2.20 We spoke at some length with regulators and pipeline experts about any requirements for regular testing of pipelines and what this entailed within their jurisdictions. While regulators were generally unwilling to impose a fixed testing regime, corrosion and pipeline specialists gave figures between one and five years as representing good industry practice in relation to intelligent pigging. This is consistent with the advice provided to Apache by external consultants noted in the previous chapter. Both regulators and pipeline specialists advised that pigging frequency should be based on consideration of a wide range of risk factors such as:

- age;
- proximity to people and/or other facilities;
- gas inventory;
- previous incidents involving the pipeline;
- findings from previously gathered information;
- recent events such as excavation near the line;
- the substance to be run through the pipe (e.g. water, carbon dioxide, and hydrogen sulphide content);
- the protective coating, including its current condition;
- CP performance including anomalous CP readings and quicker than expected depletion of sacrificial anodes;
- corrosive environments associated with wet/dry zones, salt, acidic soils and bacteria; and
- potential for the line to become uncovered or damaged externally.

2.21 Apache’s documentation and public statements assert that there was no foreseeable risk of corrosion on the 12 inch SGL due to that fact it carries sweet, dry gas and because it has an anti-corrosion coating and is protected by CP.

2.22 In terms of minimising the risk inherent in any pipeline, regulators supported the idea of treating bundles of pipes through a single risk assessment process rather than assessing them separately. This enables consideration of the risks not only related to each pipeline, but also of the interactions between pipelines in the bundle, including CP and potential damage associated with excavation, maintenance etc of adjacent lines.

2.23 We also sought information from other offshore petroleum operators and from other information sources such as those noted above to establish whether Apache’s actions in relation to maintenance of the 12 inch SGL were in line with good industry practice. We found that corrosion in wet/dry zones such as the shore crossing and CP failure where pipelines are in close proximity are common and well-known risks. Key international industry bodies such as NACE and

OGP considered that a shore crossing with exposed pipes should be an area of particular concern and that concrete casing of pipelines such as that which covered much of the 12 inch SGL at the Varanus shore crossing is not good practice due to the problem of then visually inspecting the pipeline.

2.24 Industry operators in Australia generally use in-line inspection techniques on a regular, risk-assessed, basis. Apache had done so in some cases where it identified an internal corrosion risk[56] but had not intelligently pigged the 12 inch SGL despite information from standards, industry better practice and the recommendations to do so.

Integrity management and information sharing

2.25 Inspection tests and frequencies are an important part of an organisation's integrity management system and it is the operator's responsibility to assess risk to determine inspection tests and frequencies. Integrity management can be defined as:

> *...the identification of hazards to cause failure of a system, and the mitigation measures that may be employed to reduce the probability of failure by gathering and analysing operational parameters.*[57]

2.26 An integrity management system needs to demonstrate organisational, information and technical integrity while forming part of a company-wide management system. Companies also need to develop in-house documentation that is relevant and accessible, drawing on, but not relying on, more generalised standards. A company's practices and management systems should be developed through information sharing with industry and regulators but it is important to recognise legislation, regulation and standards as the baseline requirement.

2.27 The success of an integrity management system relies on knowledge of the system and its day to day implementation by staff and contractors. Embedding integrity management skills and expectations in staff induction and training processes are critical issues in maintaining a safety culture given the oil and gas industry has experienced skills shortages over the past decade and has a high level of contractor employment. Staff retention, duplication of roles, contractor management and change management are

56 eg the Sinbad/Campbell 12 inch import line was intelligently pigged in 2003.

57 Oil and Gas Pipeline Integrity Forum, Amsterdam in February 2009.

therefore important considerations in an operator's integrity management processes.

2.28 Apache has, in part, recognised the importance of contractor management by seeking to address this issue through inclusion of 'Contract management and bridging' as an element in its Safety Management System (SMS) in its Varanus Island Hub safety case and pipeline management plan. The SMS notes that:

> *All contractors work in accordance with the Apache SMS except for Stand-alone Contractors who may use their own SMS provided that it is bridged to the Apache SMS and has similar objectives and standards of content.*

2.29 The number of consultants' reports prepared for Apache on safety-critical issues, and the diversity of companies used to provide these reports, however, is of concern. The outsourcing to such an extent for areas requiring ongoing technical expertise or, at a minimum, understanding, is potentially at a serious detriment to operational safety – particularly where key recommendations or findings are not adequately addressed and when it would appear that critical information may not always be provided to a new consultancy firm. The document trail shows a tendency to engage new consultancies to reassess the need for potentially expensive intervention when faced with a report recommending the need to do so.

2.30 Equally important is to have good integrity, resource and contract management systems, a good practice operator also needs a robust process for investigating its own incidents, auditing its own processes and implementing the lessons learned from both. This could involve a relatively independent and properly resourced internal investigation team which would investigate incidents and process safety to identify general trends that may impact on safety and integrity of operations.[58] Such a team can help to ensure that the root cause of all incidents is understood and communicated throughout the organisation.

2.31 Perhaps the most important aspect of ensuring safety and implementing lessons learned is through information-sharing. For instance, information sharing with the regulatory agencies can support development of a robust safety case and facilitate audit processes. Regulators in Victoria and South Australia, as well as onshore petroleum regulators in Western Australia, all regularly participate in HAZID and HAZOP workshops during the safety case development and revision phase. Ongoing interaction between the regulator and the operator to follow up on actions arising from audits is equally important and regular meetings to discuss actions arising

58 Shell has such a team.

are beneficial as they allow management and technical specialists to work with the regulator to amend any practices as required.

Foreseeability, organisational accidents and organisational mindfulness

2.32 As noted, there is a large amount of information and expertise relating to pipeline corrosion and particularly corrosion in the shore crossing area available to Apache and the regulators that could have assisted Apache to evaluate the risks of pipeline rupture due to corrosion at the shore crossing. This is in addition to the significant body of documentation available to Apache in the form of internal and consultant reports and regulatory documents noted in the previous chapter.

2.33 Accident and incident reports in the petroleum and gas industry worldwide indicate that it should be foreseeable that pipeline explosions due to external corrosion and loss of pipeline integrity are credible threats that require diligent management. Information available on regulatory websites, awareness and consideration of developments in standards and active interaction with regulators, industry conferences and seminars should also have alerted Apache to the need to concentrate on its integrity management and other safety-critical practices.

2.34 The question of foreseeability, however, is not resolved from knowledge of what information was available to Apache prior to the 3 June 2008 incident. While the events of 3 June 2008 are known, and likely scenarios as to their cause are considered in chapter 4, these scenarios also highlight the complexities and number of factors, systems and processes that lie behind an incident of this type – an organisational incident. Investigations into accidents in the oil and gas industries often show organisational factors to be a very significant influence, if not the root cause (see Annexes 11 and 16). In our view, the evidence suggests that this was also a significant factor in relation to the explosion on Varanus Island.

2.35 In general, contemporary thinking about how accidents happen in complex, high hazard industries hinges on the fundamental premise that accidents in such industries are complex, organisational events. Organisational events refer to Professor James Reason's three approaches to safety management: the person, engineering, and organisational models[59]. The organizational model emphasises the need for a proactive approach based on measures of 'safety

59 J. Reason, *Human Error*, CUP, 1990; J. Reason, *Managing the Risks of Organizational Accidents*, Ashgate, 1997.

health'. A basic tenet is that accidents happen to organisations, not to people. Accidents are seen as an emergent property of complex systems.[60]

2.36 The engineering model focuses on formal safety assessments as part of safety cases, involving techniques such as hazard operability studies (HAZOPS), probabilistic risk assessment (PRA), human reliability assessment (HRA), and so forth.[61]

2.37 In contrast, the person model is the traditional approach that focuses on the mistakes made by individuals at 'the sharp end'. This is the standard occupational health and safety approach, with an emphasis on 'lost-time injury frequency' (LTIF), and similar measures. Consistent with our assessment of Apache, discussed in more detail below, the safety page on its website focuses on individual competency and uses a reduction in LTIF to support the company's progress on safety management:

> *Apache has implemented a management system that, among other things, provides for ongoing training and the selection of workers with the necessary knowledge and experience to do their job safely. Apache's efforts have produced positive effects over the years, as evidenced by the improvement in the frequency of injuries to employees.*[62]

2.38 The problem, however, is that in high-reliability industries such as oil and gas production there is no direct correlation between metrics such as LTIF and the occurrence of major disasters with their consequent loss of life and/or large economic costs.

2.39 Safety is a process, not a state. The organisational approach to safety in HROs relies on two essential elements: engineering safety resilience, and managing the unexpected.

2.40 For safety assurance, it is not sufficient for an organisation to have reliable systems in place, with a failure probability below a certain stipulated threshold. An organisation's systems must also be able to deal with the irregular variations, disruptions and the degradation of expected working conditions that will inevitably occur in any system. Safety resilience must be engineered into the system:[63]

> *A resilient system has three main qualities: It can respond to regular and irregular threats in a robust, yet flexible, manner. It can flexibly monitor what is going on, including its own*

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60 E. Hollnagel, *Barriers and Accident Prevention*, Ashgate, 2004.

61 J. Reason, *Managing the Risks of Organizational Accidents*, Ashgate, 1997.

62 <http://www.apachecorp.com/Stewardship/EHS/Safety.aspx> accessed 6 June 2009.

63 A checklist for assessing institutional resilience, based on work by James Reason, is given in Annex 26.

> *performance. And it can anticipate disruptions, pressures, and their consequences.*[64]

2.41 The emphasis of resilience engineering is on a proactive stance that enables an organisation to develop robust and flexible processes, and to monitor and revise their risk models. Such an organisation is adept at anticipating, monitoring, and responding to the potential risks that they face. This approach has been described as 'readiness based on foresight'.[65] The concept of managing the unexpected is best described by Weick and Sutcliffe:

> *Unexpected events often audit our resilience. They affect how much we stretch without breaking and then how well we recover.*[66]

2.42 It is expected, then, that unexpected events will sometimes occur and pose a threat to the safety of an organisation's operations. How can an organisation prepare for that? The answer may in part lie simply in the need to be mindful and the concept of 'organisational mindfulness' has been developed to help understand the successful operation of high reliability organisations.[67]

2.43 High reliability organisations operate in an environment where it is not prudent to adopt a strategy of learning from mistakes. The essence of organisational mindfulness is the idea that no system can guarantee safety forever. Rather, it is necessary for an organisation to cultivate a state of continuous mindfulness, or unease, and always be alert to the possibility of system failure. The preoccupation of high reliability organisations with possible failure means that they are willing to accept redundancy. They will deploy more people than is necessary in the normal course of events so that there are extra resources to deal with abnormal situations

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64 E. Hollnagel, *Resilience Engineering: Why, What, and How,* 2007, p1. <http://tinyurl.com/Erik-Hollnagel-pdf> accessed 2 June 2009.

65 E. Hollnagel, D. Woods, and N Leveson, *Resilience Engineering: Concepts and Precepts*, Ashgate, 2006.

66 K.E. Weick and K.M. Sutcliffe, *Managing the unexpected: Resilient performance in an age of uncertainty*. Second edition, Jossey-Bass, 2007, p1.

67 Similar safety concepts have been described as 'chronic unease' (Reason, 1997) and 'requisite imagination' (Westrum, 1993).

when they arise. This means that staff are not routinely placed in situations of overload that may adversely affect their performance.[68]

2.44 While HROs are preoccupied with failure, more conventional organisations focus on their successes. They use success to justify the elimination of what is seen as unnecessary effort and redundancy, and they interpret the absence of failure as evidence of the competence and skilfulness of their managers. This focus on success breeds confidence that all is well, and leads to a tendency for management and staff to drift into complacency.

2.45 As a result, accidents are seen by more conventional organisations as 'fundamentally surprising' events because they call into question the organisation's model of the risks they face and the effectiveness of countermeasures employed[69]. David Woods argues that the shift required after an accident is a reframing process.[70]

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68 The concept of organisation mindfulness is described in detail in Weick and Sutcliffe (2007). Weick, Sutcliffe, and Obstfeld (1999) outlines five processes that characterise organisational mindfulness:

- A preoccupation with failure - recognising that failures, no matter how minor, provide the opportunity to learn about potential disasters. Mindful organisations see 'the reality of danger in a near miss'.
- Reluctance to simplify interpretations - using complex systems to manage their complex environment and by encouraging diverse views and approaches to operations.
- Sensitivity to operations - ensuring that someone in the organisation has a clear understanding of the 'big picture' of operations at all times.
- Commitment to resilience - a commitment to ensuring that the organisation can cope with unexpected dangers.
- Underspecification of structures - they do not rely on hierarchical structures, particularly in problem solving, when experience and expertise become more important than rank in the management hierarchy.

Weick KE and Sutcliffe KM (2007). *Managing the unexpected: Resilient performance in an age of uncertainty.* Second edition. San Francisco, CA: Jossey-Bass; Weick KE, Sutcliffe KM, and Obstfeld D (1999). Organizing for high reliability: Processes of collective mindfulness. *Research in Organizational Behavior*, 21:81-123.

69 E. Hollnagel, D. Woods, and N Leveson, *Resilience Engineering: Concepts and Precepts*, Ashgate, 2006, p24.

70 Ibid.

Safety culture

2.46 The term 'safety culture' refers to the enduring characteristic of an organisation that encompasses 'the attitudes, beliefs, perceptions and values that employees share in relation to safety.'[71] In simple terms, safety culture can be described as 'the way we do things around here'.

2.47 A widely accepted formal definition of safety culture is that produced by the UK Advisory Committee on the Safety of Nuclear Installations (ACSNI):[72]

> *…the product of individual and group values, attitudes, perceptions, competencies, and patterns of behaviour that determine commitment to, and the style and proficiency of, an organization's health and safety management.*

2.48 One key aspect, as the ACSNI outlines, is that:

> *Organizations with a positive safety culture are characterized by communications founded on mutual trust, by shared perceptions of the importance of safety and by the efficacy of preventative measures.*[73]

2.49 The concept of safety culture gained prominence after the Chernobyl nuclear power disaster focussed attention on the influence of organisational and human factors on the safety of operations in complex systems.[74] A number of significant accident investigation reports have highlighted the importance of safety culture – the 1990 Cullen Report on Piper Alpha oil-platform explosion, the 1988 Fennel Report on the Kings Cross underground station fire, and the 1987 Sheen report on the sinking of the Herald of Free Enterprise passenger ferry.

2.50 Westrum has characterised three possible types of safety culture that an organisation may have as pathological, bureaucratic and generative.[75]

- Organisations with a pathological safety culture are characterised by a closed-minded approach. Either intentionally

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71 S. Cox and T. Cox, The structure of employee attitudes to safety: A European example. *Work and Stress*, v5, pp93-106, 1991.

72 ACSNI (1993). Advisory Committee on the Safety of Nuclear Installations. *Human factors study group third report: Organization for safety*. Sheffield, UK: HSE Books.

73 Ibid.

74 The operators of the Chernobyl nuclear reactor were an experienced team who had just won an award for keeping the Chernobyl reactor on the grid for long periods of uninterrupted service (Dorner, 1996).

75 R. Westrum, *Cultures with requisite imagination*. In J.A. Wise, V.D. Hopkin and P. Stager (Eds), *Verification and validation of complex systems: Human factors issues,* Springer-Verlag, 1992.

or unintentionally, they actively discourage activities, such as open reporting, that can enhance safety. When errors are made, they focus on disciplining the individuals concerned, rather than viewing the errors as indicative of underlying systemic problems.

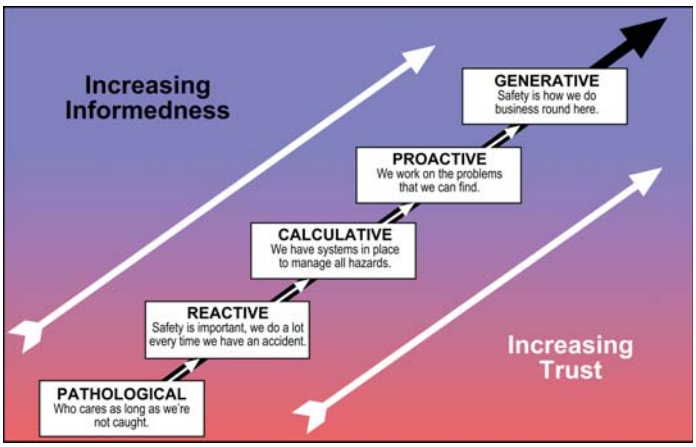
- Organisations with a bureaucratic safety culture have a better approach, but they tend to rely far too heavily on procedures and rules alone to ensure safety. Safety management tends to be carried out at a local level, rather than focussing on organisation-wide reforms. While the reporting of safety-related information is not necessarily discouraged per se, it is often not acting upon in a concerted, timely, and system-wide manner.
- Organisations with a generative safety culture are characterised by deep learning. They encourage individuals to observe, inquire, analyse, and report safety-related information.

2.51 One simple way to summarise these three organisational cultures is to look at how they treat 'messengers' - that is, individuals who report safety-related information, even when it might involve mistakes that they have made,

- pathological organisations 'shoot the messenger';
- bureaucratic organisations tolerate the messenger, but the message often gets lost; but
- generative organisations train the messenger.

2.52 Professor Patrick Hudson, in an article relating to the aviation industry in 2001, depicted these organisational safety cultures as a progression:[76]

Figure 6: It's a long way to the top: The evolution of a safety culture

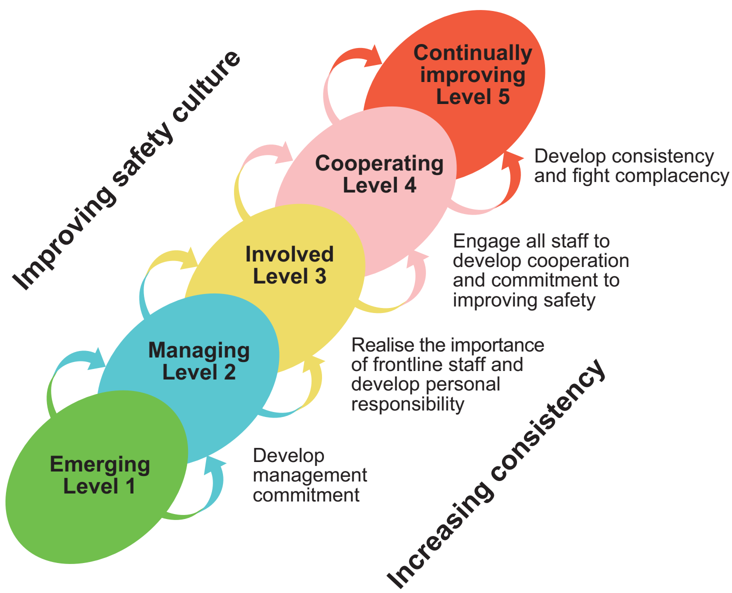


76 Hudson, P, *Safety Culture: The ultimate goal,* Flight Safety Australia, September-October 2001.

2.53 In the oil and gas industry, the HSE Offshore regulator in the UK promotes the Kiel Centre's Safety Culture Maturity Model as well as a range of other helpful human factors material (see bibliography). The Model can be seen as complementary to Hudson's model depicted above.

2.54 The London-based International Association of Oil and Gas Producers (OGP) ran a workshop in 2000 which drew on the Kiel Centre's Safety Culture Maturity Model. OGP also released a booklet in 2005 for the oil and gas industry which argues that achieving a step-change in safety requires moving beyond engineering and current health, safety and environmental management systems (HSEMS) to properly incorporate human factors. OGP's 'HSE Culture' ladder (see below) comprises five rungs similar to the Hudson diagram depicted above.[77]

Figure 7: Safety culture maturity model



77 OGP, *Human Factors: a means of improving HSE performance*, Report No. 368, London, International Association of Oil and Gas Producers, 2005.

Apache's safety culture

2.55 Clues as to where Apache may fit in the safety culture hierarchy can be found in its values and declared safety policies. The company culture is said to have evolved from the company's founder and recently retired Chairman Raymond Plank, at a moment of impasse when he said, 'Shall we do this definitely, clearly, sincerely, and above all immediately, or shall we continue to drift, talk, bicker and then do it?' The present incarnation of this approach comes from the incumbent Chairman and CEO, Steve Farris, who considers that, 'If it's worth doing, it's worth doing now.' One of several rotating corporate statements on the company's website is 'Apache Corporation ... A Sense of Urgency'.[78] This sense of urgency does not necessarily indicate a deficient safety culture – it merely increases the risk of this being the case through misunderstanding of the organisation's priorities.

2.56 NASA's adoption of a policy of 'faster, better, cheaper' preceded a number of serious accidents and events and was accompanied by cost cutting and insufficient time to reflect on unintended consequences of day-to-day decisions leading to an increasingly brittle system. Not all of the policy was bad but the changes modified the vulnerabilities or paths toward failure and exacerbated fragmentation. The tension between acute production goals and chronic safety risks is seen dramatically in the Columbia space shuttle accident.[79] The parallels with Varanus Island may suggest the need for Apache to consider serious reframing and 'resilience engineering'.

Apache's safety policies

2.57 The parent company of the Perth-based Apache Energy Pty Ltd and Apache Northwest Pty Ltd is Apache Corporation, based in Houston, Texas. Apache has operations in the US, Canada, Egypt, the North Sea (UK), Argentina and Australia. Apache Corporation's home base, the United States of America, has a prescriptive regulatory regime, and while Apache operates profitably in duty of care regimes, the

78 While, as Mr Farris and other senior Apache executives have stated, this is capable of being understood in a manner that is not in conflict with safety, it could also be misinterpreted and encourage some employees and consultants to get the balance wrong between safety and revenue operations.

79 E. Hollnagel, D. Woods, and N. Leveson, *Resilience Engineering: Concepts and Precepts,* Ashgate, 2006, pp24-30.

company appears to us most comfortable operating in a prescriptive environment.[80]

2.58 Apache has a clearly defined safety policy and won an award for safety excellence from the US regulator, the MMS, in 2008. Apache's North Sea facilities also featured as an example of good practice in pipeline integrity management in an Ionik Consulting report in 2008. Its internal safety policy incorporates the following laudable stated requirements:

> *To meet these commitments, Apache and its contractors shall:*
>
> - Recognize that no business objective is so important that it will be pursued at the sacrifice of safety.
> - Recognize that each of us has the responsibility to make the safety of our co-workers and ourselves a primary concern.
> - Comply with all federal, state, local and industry safety and health regulations and laws.
> - Identify and eliminate potential hazards. Control and safely manage those hazards that cannot be eliminated.
> - Set quantifiable safety objectives and targets that result in continual improvement. Regularly monitor and report performance against those targets.
> - Hold employees, supervisors, management and contractors accountable for their safety and the safety of personnel in their charge.

2.59 We note that a 20 December 2006 Lloyd's Register Integrity Review report stated:

> *From interview and review of documentation the [Apache] integrity management strategy appears to be regulatory and code compliance.*

2.60 While compliance is important, a true duty of care/safety case co-regulatory regime requires much more operator pro-activity. The information above and from previous chapters indicates that Apache may not view safety 'as how we do business around here' as a generative organisation would. Instead, we would suggest that its safety culture is either calculative (as defined by Hudson)[81] – that Apache's safety culture could be described by the phrase 'we have systems in place to manage all hazards' – or bureaucratic (as

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80 The US has started to embrace an outcome-based regulatory approach, incorporating the use of goal-based safety management. This change has enabled the regulator to better accommodate the reality of rapid changes in complex processes that are inherent in the upstream petroleum industry.

81 Hudson, P, *Safety Culture: The ultimate goal,* Flight Safety Australia, September-October 2001.

defined by Westrum)[82] – that Apache 'tolerates the messenger, but the message often gets lost.' Apache does go beyond compliance but its failure to be more proactive and generative seem to place it in the middle of the Westrum and Hudson safety culture hierarchies.

Apache's values, mission and strategy

2.61 Apache clearly defined values have helped it to prosper. It aims to 'Grow, succeed, innovate – and do it faster than the guys down the street.' Apache's core values are defined as:

- *Conduct business with honesty and integrity,*
- *Respect and invest in our greatest asset: our people,*
- *Conduct business with respect for people, cultures and traditions,*
- *Foster an entrepreneurial spirit; expect and reward innovation and creativity, and*
- *Drive to succeed with a sense of urgency.*[83]

2.62 The last point has the potential to conflict with longer term safety and integrity goals.

2.63 In the previous chapter we considered a wide range of documents which, if acted on, could have prevented the Varanus Island rupture. It is impossible to quantify the dollars Apache would have spent in implementing a more rigorous integrity management system over the 13 years since it became operator of the facilities in 1995. Indeed, given industry sources suggested a US$1-2 million costs to intelligently pig the 12 inch SGL, it may well be that such a system could have cost more over that period than the A$60m it is costing to repair the facility. An organisational focus on integrity, however, coupled with a strong safety culture could have enabled Apache to avoid the potential liability and the damage to its reputation with staff, regulators, downstream purchasers and other oil and gas companies which has resulted from the 3 June incident.

2.64 Instead the company failed to heed clear warning signs and advice, both from regulators and consultants, that there was a potential integrity problem, and chose to ignore the warning signs or to have the capacity to interpret them in the short term in the hope that all would be well in the long term. In line with the discussion above, Apache is a conventional organisation which focuses on

82 R. Westrum, *Cultures with requisite imagination.* In J.A. Wise, V.D. Hopkin and P. Stager (Eds), *Verification and validation of complex systems: Human factors issues,* Springer-Verlag, 1992.

83 <http://www.apachecorp.com/About_Apache/Values.aspx> accessed 6 June 2009.

its (financial) successes and interprets the absence of failure as evidence of the competence and skilfulness of its managers.

2.65 As discussed earlier in this chapter, there is a wide range of information that Apache could have drawn on in improving its safety culture. One publication by the US Center for Chemical Process Safety which highlights the importance of safety culture and human factors as significant elements in improving operational performance:

> *...seen as critical to improving performance due to the findings from investigations into major disasters in the process industries (e.g. Flixborough and Piper Alpha), other industries such as nuclear power (e.g. Three Mile Island and Chernobyl) and transportation (Exxon Valdez and Space Shuttle). ... Taking inappropriate risks, not following procedures and a belief that 'productivity is the most important thing in our business' are all indicators of a weak safety culture which invariably negates the benefits that good engineering practices, procedures, training and management systems provide.*[84]

2.66 These snapshots of information demonstrate that the oil and gas industry as a whole has been aware of and seeking to address human factor and safety culture problems within the industry for some years now. It is reasonable to expect that companies such as Apache would be aware of this trend and would seek to incorporate some of the better practice suggestions and learnings into its own processes and systems.

Foreseeability: Conclusions based on the information available to Apache

2.67 In general, information of the type that was available to Apache regarding pipeline corrosion and integrity management would enable most operators to consider whether their own in-house systems and processes would have identified and prevented such occurrences before they happened. A prerequisite for this approach, however, is for an operator to maintain its own state of 'organisational mindfulness' and demonstrate a generative safety culture in which it is actively seeking to identify risks to its operations in the future.

2.68 Literature and evolving better practice in relation to safety culture in the oil and gas industry would likewise enable most operators to look

84 Dan Crowl (ed), Human Factors Methods for Improving Performance in the Process Industries, Center for Chemical Process Safety, Wiley-Interscience, 2007, p125. The Center also cites a definition of safety culture by Uttal in 1983 involving shared organisational values (what is important) and beliefs (how things work) which interact with an organization's structure and control systems to produce behavioural norms (the way we do things around here).

at their own systems and determine whether changes need to be made. Publications by offshore regulators such as the HSE in the UK even provide guidance in the form of a booklet on the issue. Such reviews allow operators to review their own methods to reduce the probability of a similar incident in their facilities.

2.69 HROs, such as some operating in the oil and gas industry, do not hide behind a cloak of 'unforseeability'. In contrast, they are acutely aware that continued safe operations should not lull them into a false sense of security that failure will not occur. HROs revise their beliefs about the hazards they face more readily and more often than other organisations. The evidence suggests that Apache did not always act in this way. In addition, the Apache culture of urgency – 'If it's worth doing, it's worth doing now' – and its corporate focus on cost cutting may also have militated against the organisation continually reassessing what unexpected events it should guard against.

2.70 People and systems are two of the most important safety defences. No organisation has unlimited resources, and safety and business are not necessarily diametrically opposed; however resource allocation needs to be mindful of safety critical areas. Organisational mindfulness advocates that there be a certain amount of redundancy in the system. If key resources, particularly those that can impinge of safety, are routinely kept at the lowest possible level in safety critical functions, then when the unexpected happens there will be a reduced capacity for the system to quickly compensate.

2.71 Maintaining corporate knowledge can be crucial to safety. Staff turnover and/or extensive use of outside contractors can lead to a situation where corporate knowledge ebbs away or is never developed.

2.72 As documented in the preceding chapter, Apache undertook or commissioned many studies related to the safety of their operations. The July 2007 revision of the Varanus Island Hub Safety Case alone runs to over 2,000 pages in length. In addition, there was a plethora of key industry better practice information available to Apache that could have further highlighted potential areas of concern, from specific corrosion issues to integrity management and even developing and maintaining an effective safety culture. The question arises as to how can so many studies and reports produce such a mass of information, and yet a clear and foreseeable threat not be sufficiently identified and mitigated? The answer may lie in the realisation that process is not an end in itself, but rather a means to achieve a practical outcome, in this case reducing hazards to ALARP. Fundamental to any safety assurance system are physical actions such as inspection of plant, and routine and exceptional maintenance. No amount of process driven documentation can paper over that fact.

2.73 While Apache's overlooking of issues raised by many consultants was presumably not deliberate (and no doubt overlooking the potential consequences was not deliberate), it seems likely that low staffing, lack of corporate memory and inadequate systems to track issues raised by many of consultants are not unimportant in seeking an explanation. There is also a question of safety culture given Apache's excessive compliance emphasis and focus on 'lowest possible cost maximising production availability' in a duty of care/safety case regime. Safety is best assured not just by simply following regulations and mandatory standards, which by their very nature are broadly generic and not necessarily well attuned to the individual circumstances of a particular operation.

2.74 Whether Apache could have improved its safety culture relies in part on its awareness of the theory discussed above, self-awareness, motivation and capability to change. The theoretical information on the concept of a safety culture was not the only source of information on this topic available to Apache. The oil and gas industry in general has considered issues relating to safety culture, making key information on better practice safety management and culture available to HROs.

2.75 These serious conclusions raise the question of any issues with respect to regulation under the PPA and what the relevant regulators knew, or should have known, of this material and what they did, or should have done, in response. This is considered in the following chapter.

3: Regulation of Varanus Island and the 12 inch SGL

Prior to its [NOPSA's[formation, Western Australia, as a State with significant offshore petroleum resources, had a well resourced regulatory agency with experienced technical personnel.

DMP, February 2009

...major hazard OHS regulation in WA is an accident waiting to happen...

Senior WA Official, February 2009

The complex interface issues facing some projects in offshore waters across Commonwealth waters, coastal waters, State and Territory internal waters and islands in terms of occupational health and safety is confusing and adds to the risk of poor regulation of safety and potentially adds to unnecessary regulatory burdens.

Productivity Commission, April 2009

3.1 Western Australia is the only State with significant offshore petroleum resources with Island production hubs in its offshore coastal and internal waters. The oil and gas industry is regulated in WA under the following Acts:

- The Western Australian *Petroleum and Geothermal Energy Resources Act 1967* (WA PGERA);
- The Western Australian Petroleum Pipelines Act 1969 (WA PPA);
- The Western *Australian Petroleum (Submerged Lands) Act 1982* (WA PSLA); and
- The Commonwealth *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGSA).

3.2 Currently DMP is responsible for regulating activity in 215 State and Commonwealth exploration permits, 55 State and Commonwealth production licences, 20 major pipelines, 50 facilities and 10 drilling rigs. These include licences in Commonwealth offshore areas that are regulated by Western Australia under joint authority. NOPSA has responsibility for safety regulation in Commonwealth offshore areas through the OPGGSA and since 2007 in WA State designated coastal waters through conferral of powers under the WA PSLA. Further detail on the jurisdictional boundaries and legislation and its history is at Annexes 6, 7 and 8.

3.3 The impact on industry of the multiplicity of legislation and jurisdictions is significant. The Productivity Commission commented on this in its Report issued in April 2009:

> *…duplication and overlap, and inconsistent administration of the 22 petroleum and pipeline laws and more than 150 statutes governing upstream petroleum activities impose significant unnecessary burdens on the upstream sector. Project approvals are taking longer ... potentially diminishing the present value of petroleum resource extraction in Australia by billions of dollars each year.*[85]

The Commission found that:

> *The often cross-jurisdictional nature of pipelines means they are typically subject to particularly complex licensing and approval processes... .*[86]

3.4 Industry and operators are seeking clarity, efficiency and simplification of existing arrangements. In a submission to the Productivity Commission APPEA stated:

> *While the development of the individual approval requirements may have been appropriate at the time, the compounding result is that proponents are frequently now required to navigate their way through hundreds of decision points and approvals required. In the eyes of investors, this translates into hundreds of opportunities for regulatory failure.*

3.5 This regulatory burden on industry, potential confusion, and potential inconsistencies in responsibilities for different jurisdictions demonstrate the necessity to employ the same type of regulatory regime across a system.

3.6 The situation on Varanus Island clearly reflects these concerns and has created serious issues with regards to the Varanus Island hub safety case. Those parts of the Varanus Island hub which a regulated

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85 Productivity Commission, *Review of the Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector,* 2009, pxx.

86 Ibid, PC Finding 8.2, p210.

under the OPGGSA duty of care/safety case co-regulatory regime, the onus is squarely on Apache to ensure risks are reduced to ALARP. The regulatory regime on Varanus Island and more broadly for the 12 inch SGL, however, was not a pure duty-of-care/safety case co-regulatory regime. The legislation and jurisdictions relevant to Varanus Island at the time of the pipeline rupture and explosion highlight the complexity of the legislative environment with regards to safety at the time of the incident.

- Facilities on Varanus Island were licenced under the WA PPA. The Safety Case for the facilities was required as a condition attached to the PL12 licence. Regulatory responsibility for safety rested with DOIR which contracted NOPSA to provide technical advice and services including auditing on the island for an agreed monthly fee.
- Safety issues relevant to the pipelines from the Varanus Island low water mark to the mainland low water mark were, from March 2007, regulated by NOPSA through conferred powers under the WA PSLA following a 12 month transition period to March 2008.
- The mainland section of the 12 inch SGL was licensed and regulated by DOIR under the WA PGERA using DOCEP technical resources for advice.
- Safety on the offshore facilities connected to Varanus Island but located in Commonwealth waters was regulated by NOPSA under the OPGGSA 2006.

3.7 Under these arrangements, on Varanus Island itself, NOPSA mostly applied the same methods and philosophies of regulation as it would under the OPGGSA, but was considerably constrained in its actions by the fact that Varanus Island was licenced as a pipeline (PL12) under the WA PPA.

3.8 This regulatory muddle complicates our examination of who should have known what and who should have done what in relation to ensuring appropriate safety measures are applied to Varanus Island and the 12 inch SGL. We have already discussed the information available to Apache regarding the 12 inch SGL and we consider that Apache had information available to it which would have allowed it to foresee an incident like that which occurred on 3 June 2008. The involvement of the three government agencies – DOIR, DOCEP and NOPSA – in regulation of the pipeline requires consideration of what these agencies may have known, what they should have known, and what they could or should have shared regarding the 12 inch SGL in order to enable them to also foresee the risk posed by the pipelines on the Varanus Island shore crossing.

Evolution of offshore safety regulation in WA

3.9 There has been significant and fundamental change to the arrangements for regulating the offshore and onshore petroleum industry in the last five years. Prior to 2005 DOIR was, according to DMP, a well resourced petroleum regulatory agency with experienced technical personnel regulating onshore and offshore petroleum safety and integrity.[87] DMP described its predecessor as a 'one stop shop' for all safety, environment, titles and resource management matters offshore and onshore.[88] Procedures in place were said to be of a high standard with audit reports revealing a detailed understanding of facility and safety procedures in keeping with the broad industry experience and technical skills of the safety team. Follow-up on previous audit findings was reportedly a key facet of ongoing audits. Many of the processes in place were consistent with better practice regulation around the world. For instance, DOIR had implemented in 2001 a QMS (ISO 9000) procedures map for incident responses, prosecutions, safety case assessment and maintenance overview reporting. Training was stated to have been a priority and, for example, key technical staff undertook safety case training in the UK in the late 1990s.

3.10 We were told that the DOIR team was severely stretched. The petroleum industry was growing in the years leading up to the creation of NOPSA and DOIR staff struggled to keep up with this. Their range of duties not only included assessments and auditing,[89] but presentations, input to publications, industry workshops and reviewing the legislation being drafted by the Commonwealth to create NOPSA. Most staff were reportedly working 12 hour days and at weekends and there was limited support from the DOIR executive to enable them to recruit additional resources. One inter-office memo in July 2000 seeking an additional pipeline full time equivalent position (FTE) stated that:

> *Under the commercial pressures, fierce competition and low profit margins, pipeline operators are increasingly downsizing. This is certainly the case with the main players*

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87 Other advice suggests that, consistent with other jurisdictions, DOIR suffered resource constraints and difficulties in attracting and retaining staff experienced in the petroleum industry. This issue is covered in detail later in the chapter.

88 DOIR was not the only WA agency involved in approval of petroleum developments – for instance, the EPA and the Environment Minister had a role under the relevant environment protection legislation. DOIR, however, provided a first point of contact for companies seeking approvals.

89 The team had time for visits between one and four days on a facility, but we were told that the team struggled to meet planned audit schedules which required auditing each facility twice a year.

such as ... Apache... . The only strategy available to me [because persuasion was unsuccessful] is to use the power of demonstration: more vigilant reviews, audits etc... . Failing this, we would not be able to be proactive as we will be waiting for the next major accident to happen.

3.11 DMP's endorsement of the quality of DOIR's pre-NOPSA safety team should, however, be viewed in the light of other factors. For example, there appears to have been no effective database or other system that consolidated licence conditions and provided alerts when information from the licensee was due or could be sought. DOIR was also slow to respond to changes. For instance, a safety case had been a requirement for offshore facilities and pipelines under the Commonwealth PSLA (now the OPGGSA), including parts of the Varanus hub, since 1996. It was not until 30 September 1998 that DOIR gazetted a variation in the PL12 licence to require a safety case[90] under the PL12 licence pursuant to the WA PPA and it was almost four more years before the formal safety case for the Varanus Island hub was approved by DOIR in July 2002.

3.12 We were told that resource difficulties faced by DOIR also impacted on record keeping.[91] With an increasing level of activity occurring in the petroleum industry, DOIR was handling a similarly increasing volume of correspondence and regulatory documents. We have also found current DMP ability to access information from the pre-NOPSA filing system used by DOIR to be so poor that it has taken some months to locate a version of this 2002 safety case or its assessment – despite DMP still having regulatory responsibility for safety on the island. Finally a 2003 version of the safety case in which most elements remained as at July 2002, was found among safety files on a stand-alone

90 The licence condition relating to safety management for PL12 describes the contents of the safety case: *A safety case is a document containing information relevant to the identification, assessment, management and monitoring of matters, and other information, relevant to safety in the licence area. ... The safety case must demonstrate that a facility description; a formal safety assessment, a safety management system, have been appropriately developed and implemented... the licensee shall demonstrate ... his plan for the implementation, performance monitoring and continuous improvement of the Safety Case.*

91 The WA Auditor-General's report *Improving Resource Project Approvals* of October 2008 had similar findings: 'We found that agencies used manual filing systems to record progress and actions during the assessment process and relied heavily on knowledge held by individual staff for conducting assessments. Information about a single project could be placed on several files.' The agencies examined included DOIR.

hard drive. Overall, problems identified with the DOIR Petroleum Division's files include:

- critical records not being on file;
- letters sent to DOIR 'logged' by the document management system being subsequently mislaid;
- covering letter referring to attached reports being filed, without the reports actually being on file; and
- documents not located on actual file where document is registered as being filed.

3.13 We note that record keeping is a critical issue which must be addressed by any competent offshore petroleum regulator. This was an issue highlighted in the 1996 Barrell Review. We have been advised that DMP is now working to improve its record keeping with an upgraded electronic document storage system including training for all staff.

Creation of NOPSA

3.14 The creation of NOPSA on 1 January 2005 was a significant legal and administrative change to move and augment responsibility for safety regulation of the offshore petroleum industry from DOIR to NOPSA. Considerable effort was put into the planning process supporting the creation of NOPSA. The *2003 NOPSA Transitional Plan* by the Offshore Safety Steering Committee details the range of tasks that had to be undertaken to ensure NOPSA was operating on 1 January 2005. No such effort and consideration is evident, however, in relation to the functions that would continue to be regulated by WA. While DMP assures us that a change management process was in place, we have found little evidence of prior understanding of the impact of all the changes at the WA State level and no change management processes applied. As a result WA regulatory staff were left to deal with issues as they arose.

3.15 DOIR was heavily involved in the discussions, negotiations and legislative drafting prior to the creation of a single national safety regulator. Nevertheless there was evident confusion regarding what exactly was to be transferred. For instance, in the case of conferral of powers, the Ministerial Council on Mineral and Petroleum Resources (MCMPR) decision to create NOPSA on 13 September 2002 recorded:

> *Ministers endorsed the way forward for the formation of an independent national offshore safety authority. The national offshore safety authority will be a single agency covering*

> *both Commonwealth and State coastal waters and will be accountable to the Commonwealth, State and NT Ministers.*[92]

The record of meeting states:

> *WA was prepared to agree to the authority regulating its State waters on a contractual fee for service basis and reporting back to the State Minister. WA would like to retain an option for withdrawal from regulation over State waters.*[93]

3.16 The understanding of the Commonwealth and WA over time regarding what was actually agreed is discussed in detail at Annex 7. NOPSA has had conferred powers in WA designated coastal waters covered by the WA PSLA since March 2007 and for pipelines in internal waters, but has no legal authority on Varanus, Airlie and Thevenard Islands or over internal waters generally. Safety in these areas continued to be the responsibility of DOIR.

Managing safety regulation through services contracts and MOUs

3.17 As noted above, being able to attract and retain technical expertise has been an issue for the regulation of the offshore oil and gas industry for some time (see Annex 19). Part of the rationale for the creation of NOPSA was to assist in addressing this problem because an independent statutory agency can have more flexibility to offer competitive remuneration packages than a traditional public service department.

3.18 Prior to commencing operations, NOPSA had recruited about half (eight) of DOIR's offshore petroleum technical expertise base. Two others moved to industry at about that time and, to compound these changes, from 1 July 2005 the WA Government decided to transfer all but one of the remaining safety related technical resources residing in DOIR to DOCEP. However no corresponding changes were made to legal responsibilities, which remained delegated to DOIR. In effect DOIR was left with the regulatory oversight responsibilities for petroleum activities that had not been transferred to NOPSA or DOCEP with totally inadequate technical resources or skills to support those responsibilities. This included regulatory responsibility for safety in internal waters and in designated coastal waters until this latter responsibility was finally conferred on NOPSA from March 2007. DMP advised us that from 1 July 2005 DOIR was reduced to one FTE overall handling safety regulatory requirements, being the sum of part time activities of a number of people. To manage

92 MCMPR Communiqué, 13 September 2002.

93 See Annex 2.

this issue DOIR sought access to the relevant technical skills which resided in NOPSA and DOCEP.

3.19 With NOPSA they entered service contracts in relation to the regulation of safety and health for WA designated coastal waters and for internal waters and pipeline licences on Varanus, Thevenard and Airlie Islands. The State paid NOPSA a monthly 'retainer' fee of $10,000 for a range of services described in the contracts. The contract in force at the time of the 3 June 2008 incident read stated that:

> *NOPSA will provide technical advice and contractor services to DOIR for the contract areas with respect to:*
>
> 1. ***Assessment***
>   - *Evaluation of Safety Case submissions*
>   - *Recommendation to DOIR of acceptance of a Safety Case or Safety Case revisions (for construction, operation, decommissioning and/or Bridging Documents)*
>   - *Review of safety aspects of Pipeline Management Plans (and revisions) and provision of recommendations on acceptance to DOIR*
>   - *Recommendation to DOIR on approval and scopes of validation for facilities...*
> 2. ***Audits and Inspections***
>   - *Performances of audits against the Safety Cases, Pipeline Management Plans, Diving SMS or Project Plans*
> 3. ***Investigations***
>   - *Performance of investigations of safety incidents*
> 4. ***Provision of Advice***
>   - *Provision of advice to DOIR regarding safety matters relating to facilities or covered under this contract, or relevant safety/issues matters*
> 5. ***Resolution of Issues***
>   - *Endeavours to resolve safety issues with operators (or other parties) and/or provide advice and support to DOIR in resolving these issues*
> 6. ***Enforcement, Prosecutions and Appeals***
>   - *Provision of recommendations to DOIR regarding the issuing of improvement or prohibition notices*
>   - *Preparation of prosecutions in cooperation with DOIR and the State Solicitor's Office (WA)*

7. *Consultation*
   - *Consultation with operators and provision of appropriate guidance during the development of Safety Cases and project operations*
8. *Any other services*
   - *Maintenance of safety records, diving records and safety databases.*[94]

3.20 The original contract in 2005 was for three months, envisaged as a short term measure while WA drafted legislation to confer powers in designated coastal waters to NOPSA. As WA took considerably longer mirroring the legislation required to confer powers than originally estimated, subsequent contracts were signed with longer durations.

3.21 The practical application of these services contracts between NOPSA and DOIR have suffered from a key misunderstanding. NOPSA has informed us that it could not perform its duties under this contract unless explicitly asked to do so by DOIR. It is true that on several occasions, DOIR formally requested advice and services under these contracts in relation to Varanus Island - these included DOIR's request that NOPSA provide advice relating to the PL12 renewal and that NOPSA provide advice relating to the Varanus Island Hub Safety Case. Our interactions with DMP, however, indicate that the WA Department considered that the services contracts with NOPSA enabled the Authority to act without such requests, as appropriate to safety on Varanus Island. This included assessment and auditing of the Varanus Island Hub Safety Case and Pipeline Safety Management Plan.

3.22 The terms of the contract as quoted above did not indicate that DOIR was obliged to explicitly request these services from NOPSA during the course of the contract, although it was not precluded from doing so. NOPSA's view that they needed to be 'asked' to provide services under this contract is not explicit in the terms of the contract. NOPSA's view is also contradicted by its actions - as will be discussed later in this chapter, NOPSA conducted five audits on Varanus Island without explicit direction from DOIR to do so. It would therefore seem not unreasonable for DOIR to expect NOPSA to act under the contract as appropriate to ensure safety.

94 Excerpt from Services Contract between NOPSA and the State of WA through DOIR *For Services Covered by Petroleum Act 1967 (WA) and Petroleum Pipelines Act 1969 (WA)*, dated July 2007 (the contract in force at the time of the 3 June 2008 Varanus Island incident, its commencement and cessation were listed as 1 July 2007 and 30 June 2008 respectively).

3.23 We note that confusion and contradiction regarding NOPSA's actions under the services contracts with DOIR may have adversely impacted on safety regulation of facilities on Varanus Island.

In addition to the services contracts, NOPSA and the State of WA also entered into a MOU. The aim of this MOU was to build a productive partnership between the State and NOPSA for the effective and efficient administration of offshore petroleum safety. The MOU includes a Schedule which sets out the division of petroleum regulation duties between the State Designated Authorities and NOPSA under the WA PSLA following 1 January 2005.

3.24 Relationships between DOIR and DOCEP were initially managed informally as the relevant DOCEP staff remained co-located with the DOIR Petroleum Division until 2007. The relationship became more formal over time, for instance requiring correspondence between DOCEP and DOIR over particular actions. After some delayed and drawn out negotiations, a MOU between DOIR and DOCEP was signed on 24 December 2007. Under this MOU, DOCEP provided technical advice and guidance to DOIR in relation to the regulation of safety and health for which DOIR retained responsibility but for which DOIR was not obtaining technical advice from NOPSA.[95] In effect DOCEP provided technical safety advice to DOIR in relation to onshore (mainland) petroleum operations such as the 12 inch SGL above the low water mark to compressor station one.

3.25 The DOCEP/DOIR MOU did not require DOIR to pay for the services it received from DOCEP. DOCEP was expected to provide assistance to DOIR as well as attend to its substantial other duties. DOCEP has suffered from severe under-resourcing for many years with consequent major limitations on its capacity to effectively regulate health and safety under the *Mines Safety and Inspection Act 1998* and the *Dangerous Goods Safety Act 2004* as well as advise DOIR. It formally sought more resources on a number of occasions and on one occasion had obtained agreement for an additional budget of $10m per annum but had only seen around $1.9m of that in conjunction with the addition of new functions. The under-resourcing problem was described by a senior WA official as being 'a disaster waiting to happen'.

95 Varanus Island is noted as one of the facilities for which DOCEP is not expected to provide technical advice.

Integrity

3.26 From its inception, NOPSA oversaw integrity issues that had an impact or a potential to impact on health and safety under Commonwealth legislation. Because a major accident event had significant potential to impact on people, many aspects of facility integrity were therefore analysed and regulated by NOPSA. However where a potential integrity issue was considered unlikely to impact on people, such as where it involved an isolated section of pipeline like the portion of the 12 inch SGL which ruptured on 3 June 2008, NOPSA had no regulatory authority and therefore did not undertake an oversight role.

3.27 During the processes leading up to the creation of NOPSA, WA became concerned that, while NOPSA would have responsibility for occupational health and safety matters, it would not have responsibility for overall facility integrity. There was much discussion and variation in views on this issue. However it was not until after NOPSA's enabling legislation was drafted and NOPSA itself was in operation that senior officers in DOIR became aware that NOPSA was not going to have responsibility for facility integrity where integrity did not impact on health and safety. This was a significant concern for WA[96] particularly as the resources and capability that could have been utilised to undertake this responsibility were lost to NOPSA and subsequently DOCEP.[97] DOIR first raised the issue of integrity at a national level at the Upstream Petroleum Subcommittee of the MCMPR of 18–19 August 2005.

3.28 The outcome of all the changes in 2005 was that DOIR had continued accountability for regulation in State coastal and internal waters and had the regulatory role for integrity issues and minimal resources or skills with which to fulfil that responsibility. Senior management at DOIR was briefed on the issue as was the Minister. To try to deal with this the WA Minister wrote to the Chairman of the NOPSA advisory Board on 30 July 2005 saying:

> *Insofar as WA is concerned a particular problem has arisen in that NOPSA's mandate for occupational health and safety restricts its ability to provide advice on issues relating to the physical integrity of facilities. The integrity of facilities is of concern to Government in terms of public safety, environmental protection and security of supply. These functions were previously undertaken by the State's petroleum safety technical branches and which in respect to offshore have been disbanded*

96 This concern was not shared by other States.

97 WA raised this issue in Commonwealth/State forums on a number of occasions. A Commonwealth/State Integrity Working Group was established to address the issue, the outcomes of which are further discussed later in this chapter.

(mainly taken up into NOPSA) leaving the State with no technical capacity in this regard. In that an examination of a safety case would usually require an assessment of the physical aspects of a facility NOPSA would appear to be well placed to provide integrity advice. In that this circumstance is somewhat a casualty of the NOPSA system it may be appropriate for the Board to take this into consideration when evaluating NOPSA's role.

3.29 The Chairman of the NOPSA advisory Board subsequently responded indicating that the Board '...felt it did not have a mandate or resources to deal with facility integrity issues.'

3.30 The WA Minister for State Development wrote again in December 2005 to the Chairman of the NOPSA advisory Board saying:

…As you are aware, from Western Australia's viewpoint, a particular problem which has arisen with NOPSA's legislative 'safety only' mandate is its ability to provide advice on physical integrity of facilities, particularly pipelines. This continues to be a problem for Western Australia. The function was previously conducted by the State's Petroleum Safety and Technical Branch, which has been disbanded with most of the staff transferring to NOPSA and the department of Consumer and Employment Protection. The result has been a delay in approvals as other alternatives are pursued. It may therefore be useful for the Board to take this into consideration when evaluating NOPSA's role.

3.31 In a letter to the WA Minister in April 2006 the Chairman of the NOPSA advisory Board included the following:

The regulation of the technical integrity of pipelines is currently a Designated Authority (DA) responsibility, under the Commonwealth P(SL) Pipeline Regulations. For various reasons all the DAs now feel it would be more appropriate for such responsibility to be passed to NOPSA, (which currently only regulates for the occupational health and safety aspects of pipelines, and provides comments to the DAs). I am informed that this matter is currently being examined by the Upstream Petroleum Sub-Committee and that the Sub-Committee intends to report to the Ministerial Council on Mineral and Petroleum Resources in due course. I look forward to the outcome.

3.32 In a further letter to the WA Minister of 28 May 2006 the Chairman of the NOPSA advisory Board reported the following:

The Board noted that the number of gas releases increased again, and while some of this might be attributed to improved reporting the situation is not clear. The CEO has put into place a Facility Integrity National Program to improve performance in this area.

3.33 This appears to have given DOIR some confidence that their Minister's requests were being accommodated by NOPSA. Nevertheless the formal and legal position remained that NOPSA only accepted a responsibility for facility integrity to the extent it impacted on health and safety under its legislation and WA retained formal responsibility for overall integrity despite the fact the DOIR had no resources to exercise that responsibility. There was little evidence found that DOIR had sought additional resources from the WA Government to cover the integrity 'gap' and regulation of integrity per se was not undertaken effectively by DOIR. Further, the service contract between NOPSA and DOIR as late as June 2008 did not include integrity on Varanus Island among specific matters for NOPSA to provide services.

3.34 WA's correspondence on this issue was with the NOPSA advisory Board. We are surprised that WA did not also raise it with those better placed to address the issue. In particular, it is not clear why the WA Minister did not write in similar terms to the Commonwealth Minister or at least to the NOPSA CEO or Departmental Secretary. The WA Minister might also have formalised a request to the NOPSA advisory Board for advice.

3.35 The outcome of the work of the Commonwealth/State/NT Integrity Working Group under the UPGS was a decision in 2007 to amend the legislation to give NOPSA responsibility for pipeline integrity issues. When done, this would remove the integrity 'gap' with minimal resource impacts on NOPSA. While legislative drafting is currently underway at the Commonwealth level (which would need to be mirrored by the States and NT), at the time of this report the drafting of the necessary legislation had not been completed and introduced into the Commonwealth Parliament.

3.36 We note that Commonwealth legislative drafting is underway to include overall facility integrity in NOPSA's responsibilities and suggest that WA begin to prepare to mirror this legislation to enable NOPSA to regulate facility integrity in designated coastal waters once the Commonwealth legislation is passed.

Enforcement and emerging issues

3.37 Given the limited scope of the WA PPA, we asked whether DOIR had an appropriate range of enforcement penalties available for enforcement on Varanus Island licensed under PL12. DMP advised that its range of enforcement tools included directions, orders, infringement notices, stop work orders and prosecutions depending on the particular legislation that was involved. Actions against an operator's licence were also possible. However, more recently DMP has told the inspectors that taking legal action under the PPA 1969 is very difficult. This accords with the August 2004 second Reading Speech cited in Annex 7. Having the Varanus Island safety case as a condition of a prescriptive regime licence is quite alien to a safety case regime per se.[98] Despite evidence of audit recommendations not being followed up in a thorough and timely manner by the operator, there was little evidence in recent years of any enforcement tools being utilised by DOIR, or of being proposed for use by NOPSA or DOCEP.[99]

3.38 The WA PPA has also proved inadequate in allowing for appropriate information sharing between regulatory agencies responsible for the entire length of the 12 inch SGL. Information gathered by DMP under the WA PPA for the purposes of that act, for instance, may not be able to share this key information with NOPSA or DOCEP, unless those officers are appointed inspectors under the act and/or are acting directly for the purposes of the act. These potential restrictions on information sharing (including between the DA and JA) are unacceptable when dealing with complex cross-jurisdictional systems such as the Varanus Island Hub where safety issues at one end of the 12 inch SGL are equally relevant for another.

3.39 All matters associated with WA legislative change in relation to offshore petroleum safety and integrity regulation have so far proceeded slowly. The State has enacted the *Petroleum Legislation Amendment and Repeal Act 2005* which was assented to on 1 September 2005. The Act had three essential parts, containing amendments to the (then) *Petroleum Act 1967*, the WA PPA and the WA PSLA. These incorporated updated safety and health provisions for each of those Acts and repealed the *Petroleum Safety Act 1999* (which had never come into operation). Of the three, only the amendments to the WA PSLA have been given effect. These provisions mirror the OPGGSA and confer powers on NOPSA to regulate facilities including submerged pipelines. The other two parts have not to date been given effect. WA advises that this is because of delays in drafting the necessary supporting regulations and notes

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98 In this case, the September 1998 variation was in relation to the new 16 inch SGL. However, in practice Apache acted as if the condition applied to all pipelines and plant under PL12 in producing its Varanus Island Hub Safety Case. A December 1998 Pl12 variation for the two parallel 8 inch pipelines from the Wonnich platform also included a safety case condition. Variation 9P/00-01 indicated that a safety case was required for the whole of PL12.

99 The extreme impact of some of the suite of enforcement tools render them practically ineffective. Removal of licence would, for example, close down an entire facility – with major consequences not just for the operator but the economy as a whole. Only in the most extreme circumstances could this tool be used. Similar concerns might arise from use of a stop work order. Graduated enforcement tools are discussed in detail in the next chapter. NOPSA stated that it was up to DOIR to consider any enforcement action after receiving its audit reports.

that five sets of regulations covering the safety case and OHS requirements are currently being drafted.

3.40 Recently, Apache challenged DMP's provision of documents, acquired pursuant to Section 63 of the WA PPA, to an independent State/Commonwealth inquiry into offshore petroleum safety regulation following the Varanus Island incident. Justice McKerracher, the presiding judge in the case, noted:

- the argument that a pipeline is part of a wider system;
- that pragmatism indicated that WA may need to draw upon expertise from, for instance, a body such as NOPSA;
- the Inquiry's argument that 'one should not narrowly construe the purposes of the [WA PPA] Act and the Regulations in light of the significance of the [overarching safety] legislative regime (with which he agreed); but also that
- the purposes of Inquiry – specifically those parts of the Inquiry 'dealing with upstream operations generally, ships and releasing reports to the Commonwealth Minister and the MCMPR' – included, but went beyond, the purposes of the [WA PPA] Act.[100]

3.41 His honour concluded that while:

> *There is undoubtedly a high desirability of achieving safety, security and reliability in relation to gas and petroleum pipelines ... [and] ...The action of the State in releasing the s63 information to the [Inquiry] Panel was a pragmatic, convenient and sensible means of briefing the Panel ...it cannot be said that the disclosure by officers of the State to the Panel for the purposes of the 2009 Inquiry by the Panel of documents provided ... pursuant to s63 of the 1969 State Act and the Regulations ...was for the purposes of the 1969 State Act and the Regulations...*[101]

3.42 While the case was specific to provision of documents to a joint Commonwealth/WA Inquiry, it raises the issue that it may not be possible to share safety information between jurisdictions to enable the creation and assessment of, and auditing against a single Varanus Island Hub Safety Case. The Piper Alpha incident showed that the actions and activity on one facility can have a severe and catastrophic impact on another facility to which it is linked by a

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100 *Apache Northwest Pty Ltd vs Agostini [2009]* FCA 534, 22 May 2009, paragraphs 88, 90, 106, 110 and 112.

101 Ibid, paras 127, 128 and 131.

pipeline.[102] If information cannot flow freely between regulators responsible for safety on facilities regulated under the WA PPA and those regulated under other Acts, then it is difficult to understand how MAE risks on, for instance, the John Brookes platform (in Commonwealth waters with safety regulation under the OPGGSA/NOPSA) can be considered in the same safety case at the facilities on Varanus Island as is currently the case. Varanus Island appears to be the only hub which may be impacted by this issue as the Island facilities on Airlie and Thevenard do not have facilities in Commonwealth waters.

4.43 We note that the continual delays in drafting and passing legislation and regulation in WA creates uncertainty for industry and regulators alike. It also creates legislative inconsistencies across jurisdictional boundaries, imposing unnecessary costs on industry as operators have to meet multiple regulatory requirements.

R 3 **We recommend that WA ensure, as a matter of urgency, that all of its legislation and regulation mirrors Commonwealth offshore legislation and regulation and enables and facilitates the exchange of safety information between jurisdictions. In the interim, WA should seek to amend existing licence and safety case requirements to facilitate exchange of safety material.**

Regulation of the 12 inch SGL

Licensing – PL12

3.44 Licences and titles authorising the various petroleum pipelines and facilities are created and amended over a considerable period of time. For example the PL12 licence covering the majority of facilities on Varanus Island[103] was first issued under the WA PPA in May 1985 for a 21 year period due for renewal in 2006. We believe that the WA PPA is inadequate to licence a major hazard facility such as the facility on Varanus Island but WA has continued to use it as the overarching legislation for regulation on Varanus Island. Updated requirements, such as the introduction of a safety case requirement,

102 The initial fire and explosion on the Piper Alpha platform was fuelled by gas and oil from the connected Tartan and Claymore platforms as their operations crews did not believe they had the authority to shut off production, even though they had visual confirmation that Piper Alpha was burning.

103 PL12 covers production facilities on Varanus Island and both SGLs to the mean low water mark but was only one of the licences that existed on Varanus. PL29 and PL30 covered later developments that were well away from the accident site and were much smaller areas. Other pipelines that connected to the Varanus Island facility were covered by separate subsea pipeline licences or were unlicensed.

were achieved through variations to the licence. Multiple variations to PL12 have been approved over time as changes to the facility have been made and the range of activities performed on the island have expanded. There were 17 separate variations to PL12 after 1985.

3.45 Since 1985 the approach to issuing licences and the style of the licence variations has evolved. Earlier approvals were fairly prescriptive in nature due to the nature of the overarching regulatory environment. During the 1990s, safety management systems and safety cases were introduced and incorporated in variations to the licence. However, because the WA PPA did not evolve along the same lines as, for instance, the Commonwealth and WA PSLAs, the PL12 licence conditions continued to include specific requirements such as regular inspection, testing and maintenance of facilities. The current PL12 licence file comprises more than 130 pages.

3.46 In reviewing the PL12 licence it is not always clear whether a requirement incorporated in a licence condition is intended to apply to the facilities covered by the condition only or to the whole Varanus Island facility. Sometimes Apache applied any new requirements to the whole facility while at other times they did not.[104] When WA required a SMS and then a safety case through licence conditions, Apache produced a series of safety cases and ultimately a consolidated Varanus Hub Safety Case approved in July 2002.

3.47 Unfortunately this process has left the status of particular requirements in licence variations unclear. In particular, as there is no documentation specifically removing older, prescriptive licence conditions, such as the annual post-cyclone survey of the 12 inch SGL,[105] it is unclear whether these requirements should still be complied with or whether they have been overtaken. We have found no evidence on file of these issues being directly addressed and discussed with operators but it is very clear that certain aspects of the PL12 licence were not met by Apache and were not followed up by the regulator. Either the regulator was unaware or unconcerned at the lack of compliance, or there had been a verbal, undocumented agreement to let such requirements lapse. For instance, Apache undertook irregular post-cyclone season surveys but there is no evidence the results were ever sent to the Department and senior

104 Apache chose to apply other aspects of new conditions more broadly. As noted, the September 1998 licence variation concerning a safety case was applied in the context of the new 16 inch SGL but Apache applied it to the whole Varanus Island Hub and associated pipelines.

105 The original PL12 licence signed in May 1985 contained, amongst others, the following requirement: ‘The licensee shall carry out an annual external survey of the pipeline after the cyclone season and the results of the survey shall be submitted to the Director of the Petroleum Division in writing.’

long serving officers of DOIR had no knowledge of ever sighting such documents. Unfortunately, whether this requirement was not observed through oversight or through a verbal agreement cannot be determined from the official records.

3.48 As a result of the process of adding variations to the original licence rather than updating the whole licence it has become unclear whether all requirements and conditions included in the licence were applicable or, if not, which ones were no longer relevant. This leads to confusion for both the operator and the regulator, and leaves them potentially open to the accusation of not actively meeting or monitoring licence conditions. The Department advised us that its management system to ensure regulatory compliance of the Varanus facility ceased with the establishment of the NOPSA service contract in 2005, although the service contract does not indicate that NOPSA was expected to undertake this activity. We were also unable to find evidence of any effective comprehensive management system prior to 2005 that incorporated PL12 licence conditions.

R 4 We recommend that where it has regulatory responsibility, DMP develop and maintain a database of licence conditions and actively monitor compliance of those conditions. Licences should be updated to remove outdated conditions and clarify remaining applicability and any agreement to remove requirements should be documented.

R 5 We recommend that pipeline licences should be used for significant pipelines including flowlines and not major offshore facilities like Varanus Island.

PL12 licence renewal

3.49 Licences are issued for a specified period in accordance with their governing legislation. As noted, the Varanus Island license, PL12, was issued in May 1985 under the WA PPA for a period of 21 years. As a result the PL12 license was due for renewal in May 2006 with an application required to be submitted at least six months earlier.

3.50 Apache submitted an application to renew the licence on 22 December 2005, five and a half months before the expiry date. Once an application is submitted the existing licence remains valid until the renewal is either approved or declined. On 5 January 2006, DOIR responded, acknowledging receipt of the application, and stating a list of requirements for the licence renewal. The requirements included:

- A submission comprising a detailed description of the whole current plant, facilities and operational activities including maps, technical drawings and information that demonstrates how the whole facility complied with current standards and 'Best Practice'.

- The proposed terms of reference for the validation, which would comment on whether the plant and facilities covered by the PL12 licence would be fit for purpose for the next 21 years.
- An Environmental Management Plan for the whole licence area that would maintain a satisfactory environmental status throughout the life of the renewed licence.

3.51 DOIR, after acting on advice from NOPSA, subsequently approved the terms of reference for the validation and Lloyd's Register was engaged by Apache to undertake the validation exercise. DOIR's consideration of what amounted to an initial scoping document from Lloyd's in relation to validation work it was yet to perform for Apache was so cursory that DOIR actually sought advice from NOPSA on whether it should approve a 21 year extension of the licence on the basis of this initial scoping document alone. NOPSA gave clear advice that this should not happen. On 6 August 2007 Apache submitted to DOIR a copy of the Lloyd's Register Validation Summary Report for PL12, dated 10 May 2007. The 16 page summary refers to five other reports[106] which were produced as part of the validation exercise but which were not provided to DOIR or sought by it. Key findings were summarised in the Validation Summary Report as follows:

- No impediment to continued safe operations or compliance with PL12 requirements was identified.
- Vessels under the PL12 Licence which have exceeded their design life or will expire during the revalidated operating period require remaining life assessments.
- Provisions were found to be in place with continuous improvement processes to ensure safety of the operational phase and technical integrity for ongoing operations of the Varanus Island whole plant and facilities covered by PL12 as fit for purpose for the next 21 years.
- The SMS is comprehensive and integrated and covers all activities on the facility as defined by the Facility Description; has the appropriate structure and processes to foster continual improvement on safety performance; and is linked to the Formal Safety Assessment in that management of critical risk control measures are given the appropriate priority.

106 These five reports were: Integrity Audit Report : 12 to 19 May 2006 (Perth); Process Integrity Review: 12 to 14 June 2006 (VI); Process Integrity Review: 3 to 7 August 2006 (varanus Island); Process Integrity Review: 28 September to 2 October 2006 (VI); and SMS Audit Report: 6 September 2006 to 14 October 2006 (Perth & Varanus Island).

- Organisation changes and staffing provisions may adversely impact on the ability to optimally operate and maintain plant and facilities covered by PL12.

3.52 Senior DOIR officials indicated they placed considerable faith in this summary report as indicating the Varanus Island facility was in good condition and suitable for operations for the next 21 years. However, the issue of the renewal of PL12 was not progressed as DOIR was awaiting the submission of Apache's Environment Management Plan.[107] The Environment Management Plan was submitted to DOIR by Apache in late March 2009. While this was the last requirement for acceptance of the renewal, DMP has delayed acceptance on the basis that the risk assessment in the PMP should be reassessed in light of recent events and in all the circumstances.

Overall, we consider that Lloyd's Register Asia produced a document which responded to the requirements of its agreement with Apache. We are concerned, however, that DOIR did not obtain the associated Stage reports to support the renewal of PL12 despite NOPSA's earlier advice. Nor did DOIR ask that a copy be provided to NOPSA or DOCEP to seek their technical advice. Had either regulator read the full Stage reports (see chapter 1), they may have raised additional questions regarding Apache's safety systems and processes.

R 6 We recommend that if a validation report has been required to support a regulatory approval, the regulator should ensure that the complete report is received and considered as part of the approval process. The regulator should also be able to speak directly to the validation team to discussion further any issues raised within the report. This may require amendment to legislation to ensure that the regulator can engage in confidential discussions with the validator without the operator present.

The 2002 Varanus Island Safety Case

3.53 The 2002 Apache Varanus Island hub safety case was assessed by DOIR (then DMPR) which stated that it primarily used the Commonwealth's *Guidelines for the Preparation and Submission of Facility Safety Cases*, 2nd Edition, August 2000. As noted previously, this safety case was a requirement under the PL12 licence, which is a licence under the WA PPA. In this licence, a 'Safety Case' is defined as:

107 In making the point that they believed DOIR's Perth office was understaffed, Apache's submission to the Productivity Commission mentioned the Varanus Island licence renewal: 'Apache has a Pipeline License which expired in 2005 for which we have sought approval but DOIR has not yet renewed it.' Apache did not refer to the three year delay in submission of the Environmental Management Plan originally requested in January 2006.

> *...a document containing information relevant to the identification, assessment, management and monitoring of matters, and other information, relevant to safety in the Licence area.*
>
> *The Safety Case must demonstrate that a Facility Description, a Formal Safety Assessment, and a Safety Management System, have been appropriately developed and implemented in line with the guidelines issued from time to time by the Director...*

3.54 Senior WA officials have indicated their belief that they introduced a 'safety case regime' early with respect to other Australian states and Territories. However, as the WA PPA does not include the necessary provisions to consider regulation under the Act to be considered a duty of care/safety case regime and the PL12 requirement for a safety case for individual pipelines did not constitute a full safety case regime. The nomenclature and required content of the document clearly imply that it should be developed and implemented in line with a safety case regime. However, without appropriate legislation to support this requirement, it was not subject to the same conditions of enforceability as a safety case under the OPGGSA or the PSLA (and WA PSLA after 2007).

R 7 We recommend that WA support a full duty of care/safety case co-regulatory regime for offshore oil and gas across Commonwealth and State coastal and internal waters which minimises jurisdictional and regulatory interfaces and ensures that a competent regulator is appropriately resourced.

3.55 The FSA review commenced in December 2001 and was completed in February 2002 with FSA issues to be resolved by Apache by March 2002. On 22 July 2002 the Department wrote to Apache stating:

> *I am pleased to advise that the Varanus Island Hub Safety Case, incorporating the facilities listed below, has been accepted: 1. Varanus Island ... 7. Sales Gas Pipelines ... This acceptance is not an advice that the use of listed facilities in accordance with the Varanus Hub Safety Case will in fact be safe. Whilst health and safety are matters considered in making this decision, the responsibility for safe operation of these facilities remains at all times with Apache Energy Ltd. Please note that the continued acceptance of the Varanus Island Hub Safety Case will be contingent upon:*
>
> - *timely implementation of the Risk Reduction Measures;*
> - *ongoing satisfactory maintenance of the Safety Case; and*
> - *auditing of the Safety Management System in accordance with a mutually agreed schedule.*

3.56 The FSA included a section on the 12 and 16 inch Sales Gas Pipelines dated 4 April 2001. This referenced the risk assessments carried out by Stratex in June 1998 conducted prior to the installation of the 16 inch SGL. Listed threats included corrosion. It was stated that:

> *The two SGLs only form a part of the total pipeline system connected to VI. Therefore it is a conservative conclusion to state that the SGLs contribute less than 0.25 per cent of the overall risk to personnel on VI.*[108]

3.57 In relation to the offshore (submerged) SGLs, the document focus was the 16 inch SGL and reference was made to external corrosion being addressed by external corrosion coating and sacrificial anodes 'inspected annually for offshore sections and every three years for the onshore sections of the pipelines'. For pipeline onshore (from the pig launchers on Varanus Island to the submerged point of pipelines) corrosion was not cited as a risk or hazard.

3.58 The safety case FSA document included an Apache document prepared by International Risk Consultants dated 6 July 2001 and titled *Varanus Island Formal Safety Assessment Attached Report*. This noted that while offshore pipelines are considered only up to 500 m offshore Varanus Island, 'the entire pipeline inventory is included to provide a more realistic release model', and that high pressure jet gas releases are likely to be rapidly ignited. The Harriet gas import pipeline, Campbell/Sinbad import pipeline[109], and Sales Gas pipeline and header (sic)[110] were each assessed with corrosion a potential cause of jet fire in each case. The Sales Gas assessment noted that there could be fatality on HJV plant and on ESJV plant if jet fire were oriented towards it. For the first two pipelines it is noted that the 'area around onshore section of pipeline is not normally manned' (ie the beach crossing) and for the SGL 'low manning levels and diversity of escape routes from open plant' was noted. All were screened as 'A' major accident events with severity assessed as 'major', likelihood 'unlikely' and risk 'marginal'.

3.59 As noted in chapter 1, issues with relatively close pipeline spacing potentially contributing to an escalation of a MAE were not cited. Corrosion mitigation measures were also lacking in documentation in the 2002 safety case material we have been able to access. Overall, hazards and risk appear to have been significantly understated by Apache but not identified as a concern by the WA regulator.

108 At about the time of the 3 June 2008 incident we calculated that the two SGLs contributed 1,540 tonnes of about 4,100 tonnes of hydrocarbons or about 37.5%.

109 Later in the document this pipeline was termed a 'flowline'.

110 By this time both the 12 inch SGL and 16 inch SGL were had been operating for years and so the safety case should have used the plural and assessed both.

3.60 The last DOIR audit of the Varanus Island operations under Apache's safety case was from 4–7 May 2004. It included a number of positive observations and found that progress on close-out of previous audit items was 'fair' and that progress was still being made on issues such as Change Management Control. However, 'maintenance was identified as a major issue for improvement.' Assets were beginning to show their age and a specific concern included 'the amount of time spent on corrective rather than preventive maintenance ... Maintenance has a critical role in providing integrity of equipment.'

3.61 While we were given assurances that DOIR was an effective regulator prior to the creation of NOPSA, what we see from the files is at best a regulator that had competent and well-motivated staff but was seriously under-resourced and only meeting the bare necessities of its regulatory role. It was unable to identify higher levels of operator risk in WA waters and had not introduced a full safety case regime and its records and systems were inadequate.

NOPSA's role: 2007 Varanus Island Hub Safety Case and 2008 Varanus Island Hub Pipeline Management Plan (PMP)

3.62 NOPSA's direct involvement in assessing the Varanus Hub Safety Case began in 2007, when the original safety case was due for its five-yearly revision under the MOSOF regulations for the offshore sections and the WA PPA PL12 licence conditions onshore.[111] In the interim, NOPSA had audited against the earlier safety case in its own jurisdiction under Commonwealth legislation and as a contracted service provider to DOIR on Varanus Island and for pipelines. The revised safety case was submitted and accepted by NOPSA for the offshore portion on 31 October 2007. NOPSA also considered the onshore island portion under its services contract with DOIR and recommended on 31 October that DOIR accept it. After a reminder from NOPSA, DOIR, as the regulator for Varanus Island, formally wrote a letter to Apache accepting it on 6 December 2007.

3.63 During development of this safety case, NOPSA did not participate in any of Apache's HAZID/HAZOP workshops which contributed to the determinations in the safety case's FSA. NOPSA was, in its very early days, involved in sitting in on some operators' HAZID/HAZOP

111 Although this investigation focuses on facilities and pipelines located on Varanus Island that are licensed under the WA PPA, documents, information and guidance or advice relating to any of Apache's Varanus Island Hub operations (which includes facilities and pipelines regulated under the WA PPA, WA PSLA and Commonwealth OPGGSA) are relevant to this investigation due to the interconnected nature of the operations.

workshops (which contribute to developing the FSA). NOPSA has since determined, however, that this could compromise the function of the regulator and has developed a specific policy controlling NOPSA's interactions with operators.[112] Although this policy gives a general approach to dealing with operators most of the document relates to:

> *...attendance by NOPSA OHS inspectors at formal project hazard identification and risk assessment meetings, such as HAZID/HAZOP meetings and the possible impact such attendance may have on stakeholders perception of NOPSA's independence and its ability to provide assurance that risks are properly controlled in Australia's offshore safety regime.*

3.64 NOPSA states that:

> *...although there are potential benefits of attending [HAZID/HAZOP] meetings as noted above (process guidance and regulatory understanding), these benefits can be realised by other means, for example by a careful assessment of the safety case and supporting documents.*

3.65 The outcome of the policy was that general attendance of NOPSA OHS inspectors at operator project hazard identification and risk assessment sessions should not take place with attendance only as an exception on the basis of 'observation only' status. It is understandable for NOPSA to not want to compromise its assurance and enforcement functions. However, we consider that attendance at these workshops with observer status could be crucial for NOPSA to assure itself that the operator is indeed conducting a robust process and to enable it to witness potentially valuable cultural information about an operator which may not be gained from reviewing documents. We believe NOPSA would have been in a better position to discover weaknesses in the 2007 Safety Case with regards to corrosion protection measures on the shore crossing of Varanus Island discussed in chapter 1 could have been better identified had NOPSA been involved in these workshops.

3.66 In its assessment of the safety case according to its normal practices, NOPSA selected two MAEs: ship collision and hydrocarbon explosion. The latter covers most of the 42 MAEs for Varanus Island, however it is not clear to us, given that this MAE was generic across all onshore and offshore facilities, whether hydrocarbon explosion from a pipeline was specifically reviewed. Within the FSA the key safeguard (control) measures for corrosion were identified as 'corrosion monitoring' and the Apache document 'Integrity Corrosion

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112 *NOPSA Relationship Management Liaison with Operators Policy,* Rev 0 , PL202, 4 March 2005.

Management Strategy', which was not seen by NOPSA. NOPSA noted in its safety case assessment sheet the generic nature of the FSA and also that there was a degree of a lack of specificity to the FSA.

3.67 NOPSA's assessment of the Varanus Island hub safety case did not appear to specifically review the controls required to manage the MAE hazard from the SGLs. NOPSA has informed the Investigation that as one part of the safety case consideration, the MAE assessment looks at systems and processes rather than going into detail, and that assessment of the MAE hazard from the pipelines may not have prevented the incident on Varanus Island. While this is true, for the Varanus Island Hub Safety Case, which covers a number and variety of ageing facilities onshore and offshore and systems, we feel the selection of two MAEs appears inadequate. While assessing two MAEs may be adequate for a simpler safety case, the Varanus Island Hub Safety Case covered several wells, platforms, pipelines, as well as the facilities on the island itself. In light of this, more MAEs should have been subject to assessment by NOPSA.

3.68 When WA amended the WA PSLA to mirror the Commonwealth legislation in 2007, the requirement for a Pipeline Management Plan (PMP) and Pipeline Safety Management Plan (PSMP) came into force for designated coastal and internal waters (including those State waters between Varanus Island and mainland WA, see the Annex 6 Figure). Operators subject to regulation under this act were given 12 months in which to develop a PMP and PSMP, if they had not done so already. As Safety Authority, NOPSA's role in these designated waters was to accept the PSMP and advise the designated authority, in this case DOIR, of its decision. The decision to accept the overall PMP then lay with DOIR.

3.69 NOPSA accepted the Varanus Island Hub PSMP in March 2008 for the subsea segment of the licensed pipelines, including the 12 inch SGL, from the mean low water mark on Varanus Island to the mean low water mark on the WA mainland as that was NOPSA's regulatory responsibility under the conferred powers.[113] Consistent with its legislated functions, NOPSA's focus was the health and safety of persons at or near the pipeline up to these low water marks. NOPSA's PSMP assessment report also makes the general statement 'that Apache have in place a robust system for ensuring hydrocarbon containment is maintained'.[114]

113 Letter of 27 March 2008 from NOPSA to DOIR.

114 NOPSA PSMP Assessment Report, 26 March 2008, Doc N-04400 version 0.7.

3.70 NOPSA's PSMP acceptance did not include any unlicensed flowlines,[115] which carry significant inventory. These flowlines would not usually be assessed individually since they are not within the scope of the document. However, we believe that they should have been part of the PSMP assessment to the extent that they could impact on the safety and integrity of licensed pipelines in their immediate vicinity and could cause or contribute to the escalation of a MAE.

3.71 Furthermore, consistent with our comments above regarding NOPSA's involvement in the HAZID/HAZOP process for the Varanus hub safety case, we note that similar workshops were held for the purposes of the PMP and that NOPSA did not attend these workshops. In chapter 1 we discuss the weaknesses in the PMP's FSA relating to corrosion mitigation at the shore crossing of Varanus Island. Again, we believe the benefits in attending these workshops and interacting with the operator (and its contractors) outweigh any perceived risk to the robustness of the workshops and related regulatory process. Had a member of NOPSA attended these workshops, NOPSA may have been in a better position to understand the relative risk posed by different sections of the pipeline and risk mitigation process. It must be noted that a DOIR representative attended the first HAZID/HAZOP workshop for this process, but this person did not attend subsequent workshops where the risk profiles for the pipelines were firmly established.

3.72 It is important to note that NOPSA's acceptance of the PSMP did not explicitly include the portion of the 12 inch SGL on Varanus Island. The WA PPA and associated regulations, which are in force on Varanus Island and under which NOPSA acted (on behalf of DOIR as the regulator) on the island, make no reference to a PMP, PSMP, or safety case. It is a licence condition to have a safety case for PL12, but this licence makes no mention of a PMP/PSMP. NOPSA therefore considers that the Varanus hub PMP and PSMP could only be legally recognised for those areas of pipelines that were under the OPGGSA or the WA PSLA. NOPSA believes that the PMP/PSMP do not apply and are not relevant for Varanus Island.

3.73 We consider NOPSA's position to be overly narrow and legalistic, to the potential detriment of safety regulation on Varanus, Thevenard and Airlie Islands. The integrated nature of the Varanus Island operations in particular makes it imperative to consider the system as a whole, and recognise the impact of safety/integrity issues on one part of the 12 inch SGL to others.

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115 Which include the 12 inch Campbell/Sinbad line, which is adjacent to the 12 inch SGL on Varanus Island.

3.74 Furthermore, we consider that NOPSA could have provided comment in relation to the onshore Varanus Island section of the Varanus Island Hub PSMP. NOPSA also claims that, regardless of whether the PMP/PSMP could be considered for Varanus Island, they were not asked to do so by DOIR. Conversely, the Director of Petroleum and Environment Division at DMP has indicated that at the time of PMP approval, DOIR believed that NOPSA's PSMP acceptance encompassed the portion of the 12 inch SGL on Varanus Island. This apparent misunderstanding stems from DOIR's belief that it did not need to specifically ask NOPSA for advice under the services contract including advice on PSMP. NOPSA had a contrary view.

Auditing and enforcement on Varanus Island from 2005 to 2008

3.75 NOPSA conducted five audits between March 2005 and March 2008 on Varanus Island in accordance with a service contract between DOIR and NOPSA. The inspection criteria included consideration of the WA PSLA, the WA PPA, relevant State schedules and guidelines, and good oilfield practice. NOPSA would provide a draft close-out report to Apache at the audit site before departing, to be followed up with a final report in about a week, having discussed the report at Apache's head office in Perth. Under the service contract, NOPSA would complete an audit inspection report and pass it to DOIR, the organisation with regulatory responsibility for safety. DOIR then formally sent the audit reports to the relevant operator for attention. NOPSA also drafted the covering letter for DOIR which DOIR invariably signed and sent.

3.76 NOPSA's audit findings in relation to Varanus Island are described in some detail in chapter 1. In this chapter, we noted in particular a trend in adverse findings relating to Apache's auditing systems, culminating in NOPSA directing Apache, in 2007, to 'develop and implement a comprehensive audit system.' Evidence provided by NOPSA indicates that while this recommendation was noted 'closed' by December 2007, NOPSA still considered that Apache's audit systems were lacking into early 2009.

3.77 In relation to these findings, we considered why no enforcement actions were pursued regarding Apache's auditing practices. The Apache SMS within the Safety Case has an element specifically for Audit, Performance Review and Improvement, which includes a number of commitments including:

- a rolling four year program to audit all elements of the SMS;
- an annual plan;
- audits of other management systems including adherence process procedures and controls; and

- audits of the application of facility safety cases.

3.78 The safety, health and environmental protocol which outlines the audit team membership and the procedures to be followed are also referenced. Failure to meet these commitments breaches safety case conditions and could have provided a basis for some form of enforcement action using the safety case as a basis.

3.79 According to NOPSA, enforcement was not pursued in this case as the findings were made on Varanus Island, where DOIR was the regulator. This is not a valid argument, however, as the Services Contract between DOIR and NOPSA states that:

> *NOPSA will provide technical advice and contractor services to DOIR for the contract areas with respect to ... Enforcement, Prosecution and Appeals*
>
> – *Provision of recommendations to DOIR regarding the issuing of improvement or prohibition notices (where applicable).*
>
> – *Preparation of prosecutions in cooperation with DOIR and the State Solicitor's Office (WA).*

3.80 NOPSA did not recommend any enforcement action and has indicated that it is of the view that it could not do so unless requested by DOIR, while DOIR assumed that NOPSA would be forthcoming with enforcement recommendations as appropriate. This further emphasises the confusion illustrated above regarding what NOPSA would and would not do under the services contract. NOPSA was in essence acting as a contractor in undertaking inspections for the regulator on Varanus Island, following up on progress and agreeing close-outs. However, NOPSA had no conferred powers on Varanus Island and thus did not have the regulatory power to undertake any enforcement action on Apache independently.

3.81 NOPSA has further indicated that WA legislation does not give the same level of power to the safety case under the licence as the MOSOF regulations, and that enforcement under WA legislation would be a challenge. While this may be true, it does not excuse either party from taking action, or attempting to take action, where enforcement may have been necessary in the interests of the safety and integrity of a facility. NOPSA may not have recommended enforcement action to DOIR, but we found no evidence of follow-up discussion regarding the potential for enforcement actions initiated by DOIR either. Communication between these agencies was not working effectively. We found no evidence that NOPSA had made any attempt to work with WA to deal with the issues posed by the PPA legislation. However, we note that DOIR may not have welcomed discussions on NOPSA's findings and potential enforcement actions because of DOIR's serious resourcing issues.

Regulation of PL17 on the mainland

3.82 The relationship between DOIR and DOCEP with regard to pipelines on the mainland was similar to that between NOPSA and DOIR in that DOCEP provided technical advice which DOIR usually followed. Like NOPSA, DOCEP would provide its opinion on regulation of these pipelines, and even enclose draft correspondence for DOIR to transmit to the operator. There was only one instance noted in the files where DOIR did not forward this drafted correspondence to the operator. Interestingly, this instance involved the Apache Varanus Island pipelines.

3.83 In late 2006 DOCEP initiated discussions with Apache on the issue of pipeline integrity relating to PL17, which is the portion of the 12 inch SGL on the WA mainland. In December 2006 DOCEP met with representatives of Apache to discuss, amongst other things, the preparation of a pipeline integrity report. DOCEP followed up on the status of the commitments made at that meeting in February 2007 and again in April 2007 by email. The second of these emails warned that the matter would be raised with Apache management if a response was not forthcoming.

3.84 On 18 April 2007 DOCEP wrote to DOIR recommending that they formally write to the Managing Director of Apache, and providing a draft letter for consideration. This draft drew attention to the fact that the 16 inch SGL had been in operation for almost 8 years and the 12 inch SGL for around 15 years. It refers to the December meeting and the discussions on the pipeline's integrity/fitness for service and the adequacy and effectiveness of the safety management system in place. The draft letter requests Apache's advice on the status of a range of matters including '...the need and the timing when the line need to be surveyed by an on-line intelligent survey tool' (ie an intelligent pig).

3.85 DOIR redrafted the letter and sent it to the Managing Director of Apache on 1 May 2007. The letter notes the discussion on the continuing integrity of the Varanus Island gas export pipeline system and that:

> *...it is a requirement of the TPL/13 and PL17 licences*[116] *that there is a review of the continued integrity and fitness for purpose at not more than 5 yearly intervals and that a report of the review's findings be provided to the Director. This required review is now considerably overdue... I hereby require Apache Energy Ltd, as the operator of the pipelines, to provide to me a plan for the required integrity review incorporating its proposed*

116 TPL13 covers the 16 inch SGL from PL12 subsea to the mainland where it joins PL17. TPL8 covers the 12 inch SGL subsea from PL12 to the mainland where it joins PL17.

methodology and terms of reference for the review and the time frame in which the review will be undertaken.

3.86 The letter drew a prompt response from the Managing Director of Apache who responded on 7 May 2007 indicating that work was progressing on the integrity review report and that the report would be completed by the end of May 2007. On 31 May 2007 Apache forwarded the 'Sales Gas Pipeline Integrity Review' to DOCEP (but not to DOIR). The 19 page document was on Apache letterhead with an Apache document number. It appears, however, to have been produced for Apache by Perth-based company Subsea Developments (Australasia) Pty Ltd.

3.87 The Integrity Review report describes Apache's pipeline management system, the physical characteristics of the 12 inch and 16 inch SGLs, summarises the inspection and maintenance activities completed (over 5 years to December 2006) and provides an assessment of the condition of the SGLs. The report's conclusion is:

> *There are no findings from the integrity management processes performed for the Sales Gas Pipelines that provide any reason for any changes to the ongoing IMR [Inspection Maintenance and Repair] activities that are not already being addressed in the current risk assessments and anomaly tracking and close out practices. The AEL Pipeline Integrity Management process is generally following the requirements of AS2885 and any specifics included in the Pipeline License for the Sales Gas Pipelines.*[117]

3.88 In response to this report DOCEP wrote to DOIR on 5 July 2007[118] recommending that they write again to the Managing Director of Apache. In the proposed draft letter to Apache DOCEP indicates:

> *…the 5 Year Integrity Review Report provided does not meet … the intent nor the requirements of the requested plan. Also, the 5 Year Integrity Review Report does not objectively demonstrate*

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117 SGLs 5 year Integrity Review, Apache, May 2007. The summary of inspection/maintenance activity records 15 workpack activities since 2000 (nothing recorded for 2001) covering 20 separate actions, mostly annual CP surveys. The only inspection programs reported (other than some span assessments and post cyclone surveys) are a 2003 Shallow Water Inspection Program and a 2004 VI Ultra Shallow Water and Onshore pipeline inspection. In relation to the onshore section of pipelines the report notes: 'The onshore inspection of the 12 inch pipeline was carried out in October 2004 from the shore crossing to the flange immediately before the pig receiver. Whilst there were no anomalies recorded during the onshore survey, there were some areas of minor damage and corrosion noted. Subsoil pipe repair was done in 2004, as was the blasting and coating of the flanges.' On CP (generally) it is reported: 'The CP readings taken suggest that the pipeline is adequately protected.'

118 The DOCEP letter of 5 July 2007 became public after the 3 June 2008 gas explosion following an FOI request.

that the subject pipeline complies with the conditions of pipeline licence…

3.89 The draft letter goes on to suggest a range of matters that should be addressed in the requested plan and included the following:

In conjunction with the above, the necessity, manner (including the type of tool to be used) and the proposed timing when both of the lines are to be surveyed by an on-line intelligent survey tool. It should be noted that the first and second of the dual line have been in operation since 1991 and 1998 respectively. In view of the period of time that the line has been in operation, it would be considered prudent and in line with good industry practice for the line to be surveyed…

3.90 Unfortunately, this is a rare instance where DOIR did not accept DOCEP's advice as DOIR decided to not require of Apache the measures recommended in DOCEP's draft letter (including possible intelligent pigging) apparently due to concerns that the measures suggested by DOCEP were more prescriptive than could be enforced and that the upcoming PMP covering all pipelines would cover DOCEP's advice to request that Apache submit a 'plan'. There is no record of DOIR raising the DOCEP concerns with Apache or NOPSA.

3.91 In briefings prepared after the public release of DOCEP's draft letter, DOIR indicated that they sought to address the issue of the integrity of the pipeline through review of the integrity review documentation, a pipeline management plan and the safety case for the facilities. Apache submitted a PMP[119] for all of their pipelines in January 2008. The safety elements of this PMP were accepted by NOPSA and DOIR (based on advice from NOPSA) in March 2008. However, the PMP was not referred to DOCEP for advice and does not appear to address the issues of concern to DOCEP. The Varanus Hub Safety Case was submitted for review and acceptance in August 2007 and, following receipt of technical advice from NOPSA, was accepted by DOIR in December 2007. It also does not deal with the DOCEP concerns.

3.92 Subsequent to the rupture and explosion, DOIR requested that DOCEP undertake a review of Apache's Operational Pipeline Management Plan (PMP).[120] DOCEP reported to DOIR on this in a letter of 28 August 2008. Significant findings included:

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119 As required under the *Petroleum (Submerged Lands) (Pipelines) Regulations* which WA had mirrored with effect from March 2007 phased in to March 2008.

120 This is another unclear change in language – previous correspondence refers only to the PMP. It is not clear in what way the OPMP is different from the originally submitted PMP. It is possible that it is the PMP minus the PSMP, or just another term for the PMP.

> *The risk analysis in the Formal Safety Assessment is non-compliant with the requirements of AS 2885 and appears to underestimate risks. … Key controls identified in the Formal Safety assessment are not described nor demonstrated to be adequate in other parts of the PMP. … Integrity management is not demonstrated to be adequate (as a minimum considered to be meeting licence and standard requirements) through the PMP.*

3.93 The results of this review were passed to Apache by DOIR in a letter dated 21 October 2008 with the recommendation for consultations to implement improvements and revisions in the PMP. To our knowledge the PMP is yet to be reviewed. However, WA has not yet renewed the PL12 licence.

DOIR knowledge and foreseeability

3.94 Regulation of Varanus Island and the 12 inch SGL on Varanus Island has always been, and remains, the responsibility of the WA Government and currently resides within DMP (formerly DOIR). The information available to DOIR as regulator included its own records from the pre-NOPSA period as well as access to audit reports, findings and other documentary information regarding Varanus Island between 2005 and 2008. As regulator, DOIR was also in a position to request most of the documents relating to pipeline integrity and safety which are referenced in Annex 1 and those we canvass in chapter 1. DOIR also, like Apache, had access to the breadth of industry and regulator expertise outlined in chapter 2 of this report.

3.95 Noting DOIR's resourcing issues and serious lack of internal expertise relating to any form of safety regulation, let alone regulation of pipelines, it is unclear as to what it would have done with this information. At the very least, DOIR knowledge with respect to Apache's operations on Varanus Island, and in particular the information provided to it by DOCEP from 2006, should have indicated that Apache was an operator that warranted close attention.

3.96 We have found, however, that neither DOIR nor NOPSA utilised any formal risk assessment matrix or risk-based ranking to assist in prioritising its attention and resources in performing their regulatory functions. There is a wide variation in safety culture of operators in the offshore industry and in high hazard industries and in the hazards and risk that they manage. It is important that regulators assess these factors in a systematic manner and direct regulatory resources to areas of greatest risk. A formal risk assessment matrix represents global better practice offshore petroleum regulation. We have reviewed risk matrices used in offshore petroleum and determined they are used to compare the risk associated with a particular operating company against the risk inherent in a particular facility. The risks associated with the company related to the quality of risk management systems they had in place, information from auditing staff regarding the safety culture and understanding, the company's safety record and the company's historic compliance levels (including any prior prosecutions for safety/compliance breaches). The risk associated with the facility was related to age, condition, location, nature, output, culture, compliance history, complaints, any financial issues and staffing levels and competence. Such a matrix then enables the regulator to tailor its approach to monitoring and compliance by highlighting which operators present a higher risk.

3.97 In Apache's operations in Australia, there were several indicators that the operator may represent a higher risk. These include a successful prosecution of Apache, noted in DOIR's 2002–03 Annual Report:

> *DOIR successfully prosecuted an operator (Apache Energy Ltd) in relation to an incident involving a flashback from a flare that occurred in November 2001. Apache pleaded guilty in Karratha Magistrates Court in April 2003 in regard to the prosecution. Apache was fined $20,000 plus costs.*[121]

3.98 In addition, DOIR records indicate that Apache was routinely slow in responding to requests for assurance of integrity on its pipelines and in addressing some negative audit findings.

3.99 As a regulator with scarce resources, we believe DOIR would have benefitted from use of a risk matrix to assist in targeting these resources where they would be most effective for appropriate safety regulation. In Australia and overseas, regulators have formal methodologies to identify and measure risk developed over time. The Petroleum and Geothermal Group in PIRSA uses a ten factor matrix as a guide to determine surveillance of operators and regulatory decision-making. The factors are surveillance status (low supervision, low but unproven or high supervision), ground disturbance, public safety consequence, worker safety consequence, security of supply consequence, environmental consequence, routine/non-routine activity, stakeholder scrutiny, track record, and political scrutiny. Similarly, WorkSafe Victoria's Major Hazards team have developed a risk matrix to better target enforcement. Factors considered included compliance history, incidents, complaints and potential response to the tougher economic conditions.

121 This was DOIR's sole successful prosecution during that year.

R 8 **We recommend that DMP develop a robust risk assessment matrix for use in assessing and responding to the safety culture, motivation, capacity and changing risk associated with each oil and gas and major hazard operator and facility.**

Regulatory confusion

3.100 Under the processes set up following the creation of NOPSA, we consider DOIR operated as a 'post office' as they did not have the staff resources or technical expertise to review the advice provided. They accepted NOPSA work at face value and often did not even read the documents (safety case analysis or audit reports) other than the proposed draft letter. No examples were found, and DOIR officers could not recall any example, where NOPSA advice had not been followed. The same was the case for DOCEP advice, other than the advice relating to the integrity of the two SGLs covered above. There was no 'value add' from DOIR's involvement, despite its role as the agency with the Minister's delegated responsibility. In practice, DOIR acted as an extraneous interface in the process, adding to confusion and perceived diffusion about responsibility and accountability.

3.101 There was also significant confusion in DOIR, NOPSA and industry as to the regulatory boundaries within and between these agencies. Senior WA officials expressed confidence that they were clear on the dividing line between the various responsibilities, jurisdictions and licences covering the 12 inch SGL. This clarity, however, was not consistent between individuals and organisations. For example some were clear that the mean low watermark on Varanus and on the mainland was the point at which jurisdictional responsibilities changed while others thought the nearest valve above the mean low water marked the boundary. Others felt that the jurisdictional change occurred at the limit of the Varanus Island lease about 100 metres from the shore line. While these may not, at first, appear to be major inconsistencies, the existence of any doubt or uncertainty at sensitive interfaces is a cause for concern.

3.102 Industry became similarly confused with this muddle of regulatory oversight. When safety cases or requests for regulatory approval were submitted by operators to DOIR they were passed to NOPSA or DOCEP, depending on the facility location, for technical advice. Over time, files and interview information indicated that some operators began to send documents direct to NOPSA or DOCEP, not always directly providing a copy to DOIR. This highlighted the operator's confusion about who had actual regulatory responsibility. As 'delegation' is normally understood to transfer responsibility to the delegate, there would appear to be some confusion as to whether

Apache thought that NOPSA had regulatory responsibility for safety over facilities which remained under the regulatory authority of DOIR under the PL12 licence issued pursuant to the PPA.

3.103 We note that outsourcing provision of services including auditing and technical advice without conferring powers has created a situation where the regulatory authority has neither the time nor the technical skills required to assess the technical requirements of its regulatory role. DOIR's role and the use of service contracts have created confusion within industry as to which agency holds regulatory authority and has badly affected the regulation of safety for oil and gas facilities. While organisationally combining DOCEP resources with the DOIR regulatory responsibilities has at least provided immediate access to broader technical safety skills within DMP, we do not think that this resolves the situation. Safety of facilities in WA offshore areas, including islands other than Barrow, not currently covered by NOPSA continue to be poorly regulated and require legislative and administrative change and appropriate resourcing.[122]

3.104 Our view is that NOPSA represents the future direction for offshore petroleum safety regulation and that efforts must be made to further consolidate and improve the regime. As a result, we make the following recommendations.

R 9 **We recommend that WA confer powers to enable NOPSA to regulate all offshore safety and integrity including all facilities and pipelines in the water and the WA islands (including Varanus Island) which export gas by pipeline. NOPSA's authority should extend to the nearest valve on the mainland above the shore crossing or other logical system boundary.**

R 10 **We recommend that following a decision to confer power to NOPSA that includes Varanus Island, WA seek a mechanism for the Commonwealth to enable NOPSA to provide short-term regulatory services pending the conferral. This may involve the appointment of NOPSA officers and supervisors as inspectors under WA legislation.**

122 DMP has informed us that it has prepared and implemented a program of regulatory activity for WA offshore areas to address the withdrawal of NOPSA from providing these services.

Conflict between safety and environment

3.105 The six pipelines on the shore crossing at Varanus Island are located in a narrow corridor in close proximity to each other. The smallest separation, being between the outer coating of the 12 inch SGL and the 12 inch Campbell/Sinbad line, is only 167 mm.[123] This proximity increases the risk of an integrity failure in any one of the pipelines in the corridor impacting on other pipelines and escalating the impact. This is exactly what happened following the original failure of the 12 inch SGL.[124]

3.106 We were told on a number of occasions that the close proximity of the pipes was due to environmental restrictions. Historical information gathered by Apache indicates that at the time of construction there were considerable environmental concerns related to marine corals and unique indigenous animals on Varanus Island. We also heard considerable criticism that the various approval authorities did not, and still do not, treat environmental requirements holistically with safety and that safety could be a casualty if an environmental matter was a last hurdle delaying a major project. Anecdotal evidence provided to the investigation suggests this is still an issue, with examples including the location of a flare within the proposed Gorgon plant and the location of a proposed major LNG plant at Onslow (which is particularly susceptible to cyclones and storm tides) instead of at a less tidal/cyclone affected area.

3.107 It was very difficult to obtain definitive information on what environmental restrictions had been placed on the Varanus Island facility in the staged development of the facility over a twenty four year period. The environmental restrictions we could trace were very general in nature and their precise impact on the shore crossing area of Varanus Island difficult to determine. For example the approval for the East Spar offshore gas field development issued by the WA Minister for the Environment in September 1995 contained, amongst others, the following conditions: 'The proponent shall protect flora, fauna, landforms and groundwater on Varanus Island'

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123 The 167 mm is the separation between the outer coatings of the pipelines, while the pipelines themselves had a 226 mm separation with both measurements taken from the DOIR/NOPSA investigation report released on 10 October 2008. The standard applicable at the time of construction, AS 2885-1987, indicates: 'Where a pipeline is to be laid parallel or is to cross an underground structure, service, or pipeline, the clearance should, where practicable, be not less than 300 mm. Where a clearance of 300 mm is not obtainable, the pipeline shall be protected from damage that might be caused by the other structure or pipeline and separated to prevent electrical contact.' There is also the issue of possible interference from pipes crossing both near the shore and up the beach towards the HJV plant.

124 There is also the possibility of one pipeline becoming the sacrificial anode for another or of other CP interference or stray current effects.

and 'The pipeline will come ashore at a site within the existing Harriet Joint Venture Pipeline Licence area in a manner which minimises environmental impact.'

3.108 We could not locate any written evidence of a specific condition that required new pipelines on Varanus Island to be contained within the corridor approved for the original pipeline. Nevertheless that is what has occurred, and logically so from an environmental point of view as utilising the existing approved corridor would not only minimise environmental impacts but also make obtaining environmental approvals easier. A senior Apache official[125] stated that using the existing corridor had been required by the WA environmental agency and that, in order to conform with this requirement, Apache had reconsidered the planned route of several pipelines and had to use 'angles that were not ideal' in order to access the corridor. We were told that the Hadson construction of the 12 inch SGL was required by environmental authorities to restore an access road on the mainland to its original native condition. This meant an emergency shutdown device could not be installed at the shore as it could not be maintained.

3.109 There is no sign that the cumulative effect of putting more pipelines in close proximity to each other to meet an environmental requirement was considered by the various WA approval authorities. As a result, the desire to minimise environmental impacts facilitated an increased and unidentified risk that the proximity of pipelines could initiate and/or exacerbate the impact of any integrity failure.

R 11 **We recommend that the potential for conflict between safety outcomes and environmental outcomes be recognised and openly considered as part of project approvals. Moreover it is important that a holistic view is taken of major facility hubs as new developments are added to ensure risks are not being added that are unidentified and not managed. This is an issue which would benefit from further, targeted research.**

Competing priorities and internal conflicts

3.110 In Western Australia, the potential for conflict between safety and environmental outcomes has been further exacerbated by internal conflicts and competing priorities within DOIR. The Director of the Petroleum and Environment Division had responsibility for policy advice, resource management, licensing, safety regulation, titles, approvals, royalties and investigations. While some of these roles are complementary, others present substantial conflicts. A recent

125 Meeting with Apache Houston, 11 February 2009.

Victorian report[126] concluded that the Department of Primary Industry's:

> *...role in occupational health and safety is seen as fundamentally compromised and conflicted because of its location within an industry-based government department with a range of diverse and often conflicting roles and responsibilities.*

3.111 The report recommended that occupational health and safety responsibilities be separated from DPI and given to another Victorian agency (WorkSafe). The same concerns and considerations that apply in Victoria and overseas in countries like Norway are applicable to DMP in WA.[127]

3.112 We note that the split between policy, resource management, environmental regulation, safety regulation and effectively investigating major incidents and near misses is handled in different ways by different jurisdictions, but we have concluded that where practicable, the best way to ensure that each receives its due weight without conflict of interest is to split the functions into different organisations. However, whatever arrangement is applied requires a holistic consideration of interests, should include good communication and relationships, and must result in a proper balancing of safety and environmental priorities.

3.113 We note that occupational health and safety accountabilities and responsibilities should be removed from the Division in DMP responsible for resource management. If they are not conferred on NOPSA as we believe is required, they should be administered by the Resources Safety Division (RSD) within DMP separate from the Petroleum and Environment Division (PED) and be properly resourced. If RSD is now perhaps under-resourced by $15 million per annum on the mainland for its petroleum and mining roles, taking on all non-Commonwealth offshore regulation would take this deficit to a much higher figure.

R 12 We recommend that DMP review and seek to minimise potential conflicts of interest with respect to the offshore industry of its administrative arrangements, delegations and functions for policy, resource management, environmental regulation, safety regulation and safety investigation.

126 Pope, N; *Report into the Regulation of Occupational Health and Safety in Victoria's Earth Resources Industries*, May 2006.

127 We were told that the 'Ritter' report to the WA Government in relation to mine safety had a similar theme.

Conclusions

3.114 Regulation of Varanus Island and the 12 inch SGL on Varanus Island, as we have seen, involves agencies other than DOIR, although DOIR retained legislated responsibility for regulation. DOCEP, while under resourced, was operating relatively effectively as a regulator in the petroleum sector and was active in seeking additional resources and highlighting issues associated with the lack of resourcing to Ministers. DOCEP advice that we have accessed showed technical knowledge of the issues and an ability to think laterally through to the potential impacts of, for instance, Apache's inadequate management of pipeline integrity.

3.115 While NOPSA was better resourced than DOCEP, it tended to keep an arm's length in acting for DOIR on Varanus Island. NOPSA stated that it could not act under the services contract without being asked to in many areas and could not consider the PSMP in relation to Varanus Island because it was not under the PSLA. Furthermore, NOPSA did not participate in the development of the Safety Case or Pipeline Management Plan, believing this would be to the detriment of effective safety regulation for the industry.

3.116 DOIR's performance as an offshore oil and gas industry regulator for Varanus Island can be considered in relation to the MCMPR nine principles for offshore industry regulation that were agreed on 4 March 2002:

1. *An enhanced and continuing improvement of safety outcomes in the Australian offshore petroleum industry is a priority for Governments, industry and the workforce.*
2. *A consistent national approach to offshore safety regulation in both Commonwealth and State/NT waters is essential for the most cost-effective delivery of safety outcomes in the offshore petroleum industry.*
3. *The safety case approach is the most appropriate form of regulation for the offshore petroleum industry to deliver world-class safety.*
4. *The legislative framework must be clear and enforceable to ensure safety regulation motivates operators to discharge their responsibilities for safety.*
5. *The regulator must demonstrate an independent approach in implementing its legislative responsibilities and in its dealings with industry. The structure and governance of the regulatory agency must promote independence, transparency and openness.*
6. *The regulator must employ competent and experienced personnel to guarantee effective regulation of the offshore*

petroleum industry's activities and operations.

7. *The administration of the safety regulator must deliver effective safety outcomes at efficient cost to industry.*
8. *Under the safety case regime, the industry and its workforce must be empowered to identify and report potential hazards and to implement appropriate control measures.*
9. *Approval processes in safety, titles, environment and resource management must be streamlined and dovetailed to ensure no undue delay to project development in the offshore petroleum industry.*

3.117 We consider that DOIR fails to meet most of these principles to an acceptable level. There has been no enhanced and continuing improvement of safety outcomes. There is no consistent national approach to safety regulation in WA internal waters and on Varanus, Airlie and Thevenard Islands, and no duty of care safety case regime on the islands under the WA PPA.

3.118 Furthermore, the legislative framework under the WA PPA is not clear and is difficult to enforce (see Annex 7). In addition, the structure and governance of DOIR did not promote independence, transparency and openness and indeed there are serious internal compromises and conflicts of interest. The Department did not employ competent and experienced personnel to meet its regulatory responsibilities, and did not deliver effective safety outcomes. Finally, approval processes through DOIR were frequently delayed and not dovetailed.

3.119 Many DOIR organisational deficiencies predate the creation of NOPSA. For example, weaknesses in the 2002 Varanus Island Hub Safety Case in underestimating risk of pipeline corrosion at the shore crossing were not uncovered. Prior to 1 January 2005, DOIR was functioning at a basic level with no clear organisational capacity for effective, best practice regulation. In our assessment, in more recent years DOIR's safety regulatory role did not meet basic requirements.

3.120 DOIR appeared to lack strategic focus with regard to regulation of safety and integrity. The relevant division lacked the technical ability to manage its regulatory responsibilities yet we saw little evidence of this being raised at the appropriate level and insufficient fight to gain additional resources. Lord Cullen stated in relation to a deficient UK regulator seeking an excuse of being 'overwhelmed with work' that they should 'have pressed for more resources' (see Annex 16). Even when DOIR divisional management did raise issues – such as regulation of integrity – it was raised with the wrong people – noting that DOIR's Minister corresponded with the NOPSA advisory Board on this issue, but did not then take the issue up with the

Commonwealth Minister, who could logically have had a stronger role in driving a reform agenda for NOPSA and legislative change.

3.121 We also saw no evidence that the Department, or even the Petroleum Division, undertook any sort of evaluation of its role in managing safety and integrity which would have led to the reallocation of its scarce resources to provide at least a basic ability to meet its regulatory responsibilities, albeit at the expense of other functions. It is noted that some petroleum approvals were also being criticised for delay (see Annex 12). There was little planning or change management strategy in place to respond to DOIR's changing role following the creation of NOPSA and several years later, DOIR appeared to be still complaining about similar issues.

3.122 Overall, we believe DOIR became incapable of properly managing safety regulation in WA. By acting as a post box, the division confused industry and obscured safety enforcement without providing any value add.

4: Scenarios, causal factors and conclusions in relation to the Varanus Island incident

Pipeline explosions are rare and it typically takes months to determine the cause. Everything must be examined, from the manufacture and design of the pipe to its installation and numerous environmental factors. ... All told, the pipeline was the subject of more than 50 inspections, audits or reviews conducted by top international consultants and regulators – with no warnings that the pipeline had a corrosion problem or other issues that could lead to its failure.

Apache's media statement in response to the investigation report on 10 October 2008

Apache remains focused on determining the complex and precise cause of the explosion, which was highly unusual and not reasonably foreseeable. ... Apache is conducting an extensive, technical, complex, and methodological scientific-based investigation to determine the complex and precise cause of the explosion. It is premature to reach any conclusions before that investigation is completed. Apache has sought to cooperate with DoIR to identify the root cause(s) of the explosion and to try to ensure that this type of incident does not occur in the future. ... the [investigation] report fails to include a critique of the numerous DoIR and NOPSA inspections and of their oversight responsibility

Apache's formal response on 6 February 2009 to the 10 October investigation report

In fact, Varanus is one of those matters where blame is actually irrelevant because it is in everyone's interest to understand what happened and make sure it never happens again with possibly more damaging consequences.

Slugcatcher: the truth behind the Varanus Island fire, petroleumnews.net, 25 May 2009

4.1 We engaged Dr Rolf Gubner, the Professor of Corrosion from Curtin University of Technology in Western Australia to assist us with the detailed technical issues. In his report dated 8 June 2009 (Annex 5), he summarises that:

> *A number of investigations into the incident have been performed by several consultants and experts in the field. There is no doubt that the incident was caused by severe external corrosion of the 12" Sales Gas Pipeline, where a long section of the pipe thinned sufficiently not to withstand the operating pressure at the time of incident. The resulting fracture has most likely caused the gas escaping to ignite, resulting in a fire that directly impacted on the close by 12" Sindbad/Campbell gas pipeline (ca 226 mm distance between the pipes), which resulted in a series of further ruptures of other pipelines. The timeline of the incident and series of events has been well established and is not subject to further discussion in this report.*

4.2 The October 2008 DOIR/NOPSA investigation into the pipeline rupture and consequential fires on Varanus Island identified three main causal factors considered pertinent to the incident:

1. *Ineffective anti-corrosion coating at the beach crossing section of the 12" sales gas pipeline, due to damage and/or disbondment from the pipeline.*
2. *Ineffective cathodic protection of the wet-dry transition zone of the beach crossing section of the 12" sales gas pipeline on Varanus Island.*
3. *Ineffective inspection and monitoring by Apache of the beach crossing and shallow water section of the 12" sales gas pipeline on Varanus Island.*

4.3 The Executive Summary to that report also highlighted that:

> *There are aspects of some lines of investigation that have not been settled, principally due to delays by Apache in providing information and delays in forensic testing of pipe samples. In particular:*
>
> - *Completion and full analysis of the forensic testing of pipe samples;*
> - *Statements from key Apache personnel (Apache on behalf of its key personnel declined requests for interview);*
> - *Identification of specific technical details relating to the cathodic protection of the 12" sales gas pipeline.*

4.4 We broadly agree with the main causal factors listed and the caveats (see further below). However, while the terms of reference were reasonably broad, the focus of the DOIR/NOPSA investigation was on regulatory compliance, particularly to assess whether Apache had committed any offences. The investigation specifically did not look at any potential regulatory weaknesses and it would have been difficult for the main regulators to objectively do so. It also was unable, in the time available, to assess some important material underlying the causal factors identified.

4.5 In an email dated 3 October 2008, DOIR requested that NOPSA amend the title of the investigation report from 'Working Document' to 'Final Report' as follows:

> *Could you please consider the proposed corrections below, incorporate them and provide the revised report including conclusions ... as early as you can next week? Could you also formally transmit the report with a cover letter? ... this will then be a final report.*

NOPSA agreed to this in an email three days later:

> *I note your reference to the Working Document as a [final] report and will adjust the title of the document accordingly, unless you advise otherwise.*

The correspondence provided to us does not indicate that DOIR advised otherwise.

4.6 Apache reacted very quickly to criticise this report[128] on a range of bases including the expertise of the investigators, the incomplete testing results, a purported lack of objectivity and a failure to appreciate the inspection regime for the 12 inch SGL (see also Annex 2). Apache noted in this criticism that it considered the rupture was 'not reasonably foreseeable'. For the reasons given in chapter 1, we do not agree with this view. In addition, after the high pressure pipeline ruptured, it was entirely foreseeable that intense pool and jet fires would impinge on other gas pipelines in close proximity and that the HJV plant itself would be at risk. These matters are have been examined in chapters 1 and 3 as part of our review of Safety Case and Pipeline Safety Management Plan documentation associated with the PL12 licence onshore Varanus Island. Potential root causes linked to organisational and human factors and safety culture are also examined in chapter 3.

128 Apache publicly released its first critique on 10 October 2008 and subsequently, a more formal document was sent to DMP on 6 February 2009.

Incident causality

4.7 The initial rupture of the 12 inch sales gas export pipeline and almost immediate rupture of the adjacent 12 inch Campbell/Sinbad import pipeline on 3 June 2008 occurred at the north east beach crossing onto Varanus Island in an area between the low and high tides. By 6 June 2008 the large crater formed by the associated explosion had mostly been filled in by sand from the incoming tides[129].

4.8 In this area, the 12 inch SGL (and the 12 inch Campbell/Sinbad line) was covered by the same 4.5 mm asphalt enamel anti-corrosion coating and 25 mm concrete outer weight coating as the 70 km subsea section of the 12 inch SGL. It was not deeply buried and more or less of it was covered by sand and sandy soil as it emerged from the water depending on previous tidal and cyclone events. This meant that in a harsh saltwater environment subject to high daily land temperatures, pipelines carrying large hydrocarbon inventories were unable to be readily inspected for external corrosion. Even when exposed by the tides, the concrete outer coat prevented visual inspection of the anti-corrosion coating and any corrosion of the steel pipeline within. At one point by 2004, sections of the concrete coating had fallen away and exposed the corroded 12 inch SGL pipe beneath it. This indicated that there was inadequate protection from the anti-corrosion coating and the CP system. Apache's response to this was clearly unsatisfactory (see chapter 1).

4.9 In our discussions with regulators and industry in Australia and overseas, the shore crossing region was generally regarded as a region of particular vulnerability (see chapter 2). That said, there were a variety of views expressed on how best to address the vulnerability. Pipeline and corrosion experts also suggested that in their experience there are occasions when operators of major petroleum facilities failed to give proper focus to this issue. When this occurred there was a risk that the accepted design of the corrosion protection system would be more influenced by the cost than by robust design and optimum levels of protection. We also found a gap with Australian Standard AS2885 in relation to the shore crossing zone. We consider that the understanding of regulators associated with the 12 inch SGL at Varanus Island also appeared to be inadequate (see chapter 3).

4.10 Apache's documentation on the CP systems applying to the 12 inch SGL was confused and confusing (see chapter 1). Almost a year after the incident and after the damaged pipelines had been replaced and were again operational, we made a formal legal

129 ALERT/Burgoynes report, photograph taken 6 June 2008, 16 September 2008, p53.

request under s63 of the PPA for details of the CP systems both before and after the incident. These had, as noted above, been highlighted as a central issue in the 7 October 2008 DOIR/NOPSA investigation report. Apache responded that it was conducting a search for relevant documents in relation to the CP systems before the incident and that this would take some time. Some initial documents were provided in early June with others still to be identified. Even more surprising, as at 10 June Apache had still been unable to provide us with documentation in relation to the CP systems put in place after the incident. Our understanding is that these are the same as before the incident despite the manifest failure of those systems to prevent the corrosion. It is difficult to understand why it was rebuilt to the same design if the failure was, as claimed, unforeseeable.

4.11 Based on the conflicting CP design information, the following scenarios are possible. No allowance having been made for the varying wetting and drying and resistivity of the sand and soil as the pipe came onshore would lead to intermittent CP of this section of the pipeline. Some documentation suggested the possibility of a further isolation joint near the low water mark which would have left the shore section between isolation joints without any CP system. Still further material suggested additional anodes on the shore near the plant.

4.12 Professor Rolf Gubner, summarises that:

> *For cathodic protection to work, the section to be protected needs to be immersed in an electrolyte (or buried in wet soil of a low electrical resistivity). The pipelines crossing the Beach of Varanus Island are only buried in shallow sand (fast draining, high resistivity above water line) and the level/degree of coverage with sand is changing with the seasons. Therefore, the CP system for the shore crossing was not reliable and extra care should have been taken to ensure the integrity of the coating system (visual inspections, excavations and/or intelligent pigging). To rely on CP measurements to verify that the pipelines are protected against corrosion for the section where the incident took place shows a lack of understanding of CP.*

4.13 Professor Gubner also notes that if extra magnesium anodes have been installed near the HJV plant and are above the waterline, they will have little to no effect because of the good draining properties of the sand. Documentation for the original CP design was undertaken for the then operator, Hadson, by J P Kenny. The documentation provided by Apache in early June 2009 suggests that the design did not consider other pipelines in close proximity to the 12 inch SGL. However, while Apache may have inherited an initially poorly designed anti-corrosion system, it had numerous opportunities to address this in the ensuing 14 years.

4.14 In addition to the design of the 12 inch SGL and its anti-corrosion protection systems, the pipeline came onshore through a relatively narrow cut through the island reef alongside five other pipelines of varying size and age. The oldest, dating from 1986, was the 30 inch crude oil export pipeline and the newest was the 16 inch sales gas pipeline dating from 1999. The 12 inch export SGL and adjacent 12 inch Campbell-Sinbad import line dated from 1992. Some of the pipelines crossed each other in the water and others crossed near the HJV plant on the water side of the isolation joint. The widest gap between pipelines was 6 m and the narrowest (between the two 12 inch pipelines) less than 0.3m. This compares with a common industry standard of a minimum of seven meters of separation to avoid the risk of stray current interference.

4.15 As noted in chapters 1 and 3, direct and implied environmental requirements appear to have influenced the manner in which the pipelines were routed through the reef and onto the shore of Varanus Island. The close proximity of the pipelines increased the risk of multiple explosion and the scale of an incident if any one pipe ruptured.

4.16 Our understanding that CP for the pipelines was designed and implemented on an individual pipeline basis rather than as a holistic system, raised the possibility of interference effects between the pipelines. There was also the possibility of interference from other CP systems on Varanus Island such as the large crude storage tank and from stray currents from systems and equipment on the island. Professor Gubner advised us on this:

> *To my knowledge, no efforts have been made to investigate the risk for interference between the multitude of pipelines and installed equipment on Varanus Island. In the area of the incident are six pipelines installed next to each other over a width less than 10 meters. The pipelines are crossing each other closer to the processing facility and the offshore section the sales gas line is crossed by two pipelines (at KP67.665 and KP66.17). AS 2885.1-2007, Appendix C Threat Identification, states that Threat Identification consists of all threats to the pipeline. External interference and corrosion are explicitly named. Any pipeline that follows AS 2832.1 (Cathodic Protection) needs to take into account the risk for stray current corrosion and interference from other steel structures in close proximity of the pipeline. Even leaving the standards to the side, the high risk of interference from nearby CP systems is mentioned in nearly every CP design book and books that deal with pipeline corrosion, e.g., Peabody's Control of Pipeline Corrosion, first published in 1967 by NACE International.*

Corrosion science

4.17 Corrosion science has a long history[130]. Corrosion is a well understood electrochemical process involving the transfer of electrons from one material (the anode) to another (the cathode) in what amounts to an electric current. In the oil and gas and petrochemical pipeline industries, internal corrosion mainly results from unprocessed hydrocarbons containing acidic and other contaminants, while external corrosion mainly results from environmental factors such as salt and acidic soils and bacteria. Both types of corrosion can be accelerated by temperature and other factors[131]. Because corrosion is an electrochemical process, it is possible to use various types of direct and 'sacrificial anode' currents to protect pipelines and metal structures from corrosion by effectively reversing flows of ions and neutralising a corrosion process. This is termed cathodic protection (CP). Just as CP currents can be used to reduce corrosion, stray currents from plant, pipelines and machinery near a pipeline or metal structure can accelerate corrosion. The dependence of corrosion on differences in electrical potential and movement of ions is fundamental.

4.18 We note that for many decades the oil and gas industry has been very conscious of the risks created by corrosion to the integrity of pressure containing systems and to the containment of hydrocarbons under high pressure and potential for this to lead to a major incident with loss of life[132]. Cathodic protection of pipelines was applied in the US from 1928 and included the concept that a protective potential of -0.85V against a saturated copper/copper sulfate electrode provided sufficient protection against corrosion. It has also been found over time that most failures result not from uniform corrosion but from localised pitting corrosion[133].

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130 The works of Plato (427-347 BC) contained the first known written description. Corrosion protection using bitumen coatings dates back to antiquity. A description of the corrosion process deriving from the Latin corrodere (to eat away, destroy) first appeared in 1667. Also, according to von Baekmann: 'The active and passive electrochemical processes on which the present-day corrosion protection is based were already known in the 19th century, but reliable protection for pipelines only developed at the turn of the 20th century'. W. Von Baeckmann, *Handbook of Cathodic Corrosion Protection*, 3rd edn, 1997, pp1-2.

131 According to Riskin, the factors defining the corrosion rate of metals in seawater, in the absence of stray currents, are divided into chemical, physical and biological, and J. Riskin, *Electrocorrosion and Protection of Metals: general approach with particular consideration to electrochemical plants*, Elsevier Science, 2008, p25.

132 See for example, texts such as M. Parker & E. Peattie, Pipeline Corrosion and Cathodic Protection, 3rd edn, Gulf Professional Publishing, 1988; W. Von Baeckmann, Handbook of Cathodic Corrosion Protection, 3rd edn, Gulf Professional Publishing, 1997; and J. Riskin, *Electrocorrosion and Protection of Metals: general approach with particular consideration to electrochemical plants*, Elsevier Science, 2008.

133 W. Von Baeckmann, *Handbook of Cathodic Corrosion Protection*, 3rd edn, Gulf Professional Publishing, 1997, pp16, 29.

4.19 Metals can be susceptible to attack by 'stray' electric currents that can then lead to corrosion. This corrosion under the attack of external currents is termed 'electrocorrosion'. According to a recent text by Joseph Riskin:

> *Electrocorrosion and the protection of metals under the conditions of attack by the external currents named stray currents on underground pipelines and constructions, have been thoroughly studied. A vast amount of scientific knowledge and practical experience has accumulated in this field. ... Soil is the most widespread environment for attack on metals by stray currents. ... Spreading in the ground, currents create electric fields at distances of tens of kilometres from their source.*[134]

4.20 Riskin continues:

> *For underground constructions, general non-uniform corrosion is typical. In the absence of an external current, its average rate is nearly 0.2 – 0.4 mm/year.*[135]*... The most widespread means of protection are anticorrosive coatings and cathodic protection. These can be applied separately or in combination ... Factors of aggressiveness, such as acidity, the presence of oxidizers or activators and temperature, are considered when choosing materials and ways of protection, as these characteristics are usually known in advance. In contrast, attack by stray currents on the metal structure is not always expected, and consequently, it is not always taken into account. ... As stray currents are one of the most dangerous factors causing corrosion damage to metals, methods for their detection and control, as well as a means of protection of constructions from their attack, are usually standardised and regulated.*[136]*... Methods of current detection on pipelines and other underground metallic structures, to a significant extent, are based on measurements of voltage difference between the structure and the ground. The potential of the metal is measured with respect to a copper-copper sulfate reference electrode*[137]*.*

4.21 It is common for pipelines on land and near land to be buried below water tables to create a moist and relatively stable environment for CP. Many steel pipelines are covered with an anti-corrosion

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134 J. Riskin, *Electrocorrosion and Protection of Metals*, Elsevier BV 2008, pp23-4.

135 Ibid, p24 citing ND Tomashov, Theory of Corrosion and Protection of Metals, The Macmillan Company, New York, 1996.

136 J. Riskin, *Electrocorrosion and Protection of Metals*, Elsevier BV 2008, p25, citing SA Bradford, Practical Handbook of Corrosion Control in Soils, ASM International, Casti Corrosion Series, New York, 2000.

137 Ibid, pp25-6.

protective coating that allows CP to operate in areas where the coating has been damaged during transport or burial of the pipeline. Such coatings form a primary barrier to corrosion but inevitably break down over time (on the basics of pipeline corrosion more generally see Fessler in Annex 10). There are specialist university courses in corrosion engineering and well established professional bodies such as NACE in the US that specialise in corrosion science and practical operational standards. We were pleased to be advised that a number of Australian regulators led by Victoria are meeting regularly to discuss and share information about interference and stray current effects on corrosion.

Corrosion scenarios

4.22 As a result of the other detailed investigation and technical reports available and annexed to this report, we have chosen to deal with external corrosion causality and scenarios at a higher level in an endeavour to clarify some of the main issues involved. We did not have access to Apache's root cause analysis and some of its CP material included in our terms of reference and had to complete this report based on what was available.

4.23 At our request, Professor Gubner in Annex 5 reviewed and draws on the material from the original investigation (Annex 1), our assessment of documentation from Apache (chapter 1) the extensive PearlStreet metallurgical analysis, the Townend metallurgical review (Annex 3) and the Martin corrosion assessment (Annex 4). Professor Gubner outlines four scenarios that could explain the corrosion based on well-known mechanisms. In doing so, he notes that in addition to the lack of historical CP data from Apache, there was an incomplete analysis of the corrosion products on sections of the 12 inch SGL less affected by fire[138]. The four scenarios are:

138 On this, Professor Gubner states: 'The reports that have been contracted to investigate the 12" Sales Gas Line samples concentrated on the extent of corrosion, the fracture, the microstructure and mechanical properties of the pipeline material and to some extend on the composition of the corrosion products (elemental analysis). Little data appears to have been collected about the type of coating, the thickness, the adhesion of the coating at locations on the pipeline unaffected by the heat of the fire. Little data was obtained about the condition of the pipelines across the entire length of the shore crossing. This data would have been extremely helpful to reconstruct the corrosion rates, the efficiency of the CP system, etc. Without this information, any attempt to construct the corrosion failure mechanism is based on assumptions and similar cases. The lack of such potentially significant data may be indicative of a superficial investigation by the operator despite liaison with regulators and more than 12 months having elapsed since the 3 June incident.'

1. **Coating failure due to lack of adhesion during application**
   This corrosion scenario has been developed by Martin (Annex 4) and the primary cause for the corrosion failure is attributed to a possible lack of adhesion when the coating was applied, or a loss of adhesion early in the life of the pipeline. His argument is that a typical corrosion rate under disbonded coating would be in the order of 0.5 mm per year, thus the loss of adhesion would have taken place early in the life to achieve the loss of 10 mm material. Professor Gubner believes that while this is a plausible explanation, normally coating application is subject to inspection and a poor adhesion should have been noticed at the time of installation.

2. **Coating Failure due to interference with other structures – Direct Current**
   Professor Gubner states that since the six pipelines at the shore crossing are of different age it is likely that the pipelines have different potentials. This could result in a current flowing between pipes at the first point of sufficient soil conductivity which would be in the tidal zone. The area where the current leaves the pipeline is the area where the steel dissolves. This corrosion mechanism still needs the coating to fail first or initiate at a defect in the coating due to stone chipping or other mechanical damage during installation. Relatively high corrosion rates of 0.7 mm/year could be explained through direct current corrosion. It is also possible that the installation of the 16" sales gas pipeline in 1999 could have caused the interference to occur (e.g., disrupted adequate grounding), and the induced direct voltage and current was sufficiently high to lead to the adhesion failure of the coating (cathodic disbondment) and subsequent relatively high corrosion rates of about 1 mm per year could be responsible for the failure. Alternatively, the 8 inch Harriet crude oil pipeline may also have acted as a current collector and sink leading to its good condition vis a vis the 12 inch SGL.

3. **Coating Failure due to interference with other structures – Alternating Current**
   Professor Gubner notes that there is no evidence of any measurements being made to evaluate the risk for AC-corrosion (although named in AS2885 and AS2331 as possible threats for pipelines). In a similar scenario as described above, but this time a faulty grounding inside the facility has induced an AC voltage into the pipe system. AC-corrosion is often very localised and induced at small coating defects. While it is unlikely that AC corrosion would cause the coating disbondment on such a

large scale as observed on the 12” Sales Gas Pipe Line, AC-currents can pass through a damaged coating with greater ease (depending on the frequency) than direct currents. Taking a loss of adhesion of the coating system as given, an AC-voltage of 30V could have resulted in sufficiently high corrosion rates to cause this failure within a period of 10 years (dependent on the soil/sand resistivity at the location), a higher AC Voltage would have accelerated the corrosion rates, to perhaps 2 mm per year. The area where the rupture of the pipeline took place (and the main corrosion on the sales gas pipeline was observed) might have been, looking from the facility, the first point where the beach sand was sufficiently wet at regular intervals for the AC current to exit the pipeline into the ground.

4. **Coating failure and cathodic disbondment due to CP over protection**

According to Professor Gubner, the installation of magnesium anodes close to the processing plant results in a high potential and at potentials of greater magnitude than -1.24V (vs Copper/Copper sulphate electrode), hydrogen evolution is possible at the steel surface underneath the coating. The hydrogen gas can lift off the coating from the surface, resulting in a loss of adhesion and a water and gas filled bubble which will eventually rupture and expose the steel to the environment. Corrosion is possible inside the bubble, as the CP current cannot pass through the intact bubble at sufficient rates to protect the pipe. Even if the bubble ruptures, the CP current will not be able to protect the pipe inside the crevice between the pipe and the delaminated coating. However, Professor Gubner argues that since the CP system obviously did not work in areas where the coating has disbonded at field joints, as shown in the Netlink report from 2004, this scenario is unlikely. Nevertheless, cathodic disbondment could have taken place from other intermittent interference (e.g., inadequate earthing during welding work), resulting in damage to the coating, and the poor CP performance resulted in corrosion rates as stated in the sections above. Apache’s documentation and consultancy reports warned of the danger of such disbondment but there was no evidence of follow-up evaluation in instances of potential exceedences.

4.24 Some international investigation reports of ruptures, explosions and fires resulting from pipeline corrosion suggest that even more rapid corrosion is possible (see Annex 11). Professor Gubner has examined these also. However, these are all publicly documented and reinforce the need for good operator systems and operator vigilance.

4.25 In summary, Professor Gubner states:

> *There are four corrosion scenarios resulting in different corrosion rates. All four are plausible, but little data is evident to prove or disprove the one or other. Corrosion product analysis performed by PearlStreet Metlab (8A5/MET) showed high levels of carbon and oxygen to be present in several samples. This is indicative that carbonates have formed, which is further supported by the visual description of the corrosion products sampled. The presence of carbonates is an indication of high levels of cathodic activity; either due to stray currents or cathodic protection current, the latter could only be intermittently present when the waterline was above the pipeline. However, even at extremely high corrosion rates (2 mm/y) the corrosion should have been picked up during the annual visual inspections and CP-surveys, but latest in 2004 since it was explicitly shown in the Netlink report that the pipeline showed significant corrosion. The quality of the CP surveys did not take into account the poor conductivity of beach sand. Measuring the CP potentials is, therefore, close to meaningless, if not compensated for the soil resistance at the location of the measurement. Correct monitoring of the CP-current over a long period of time, e.g, over several high tide/spring tide cycles, could have revealed that the current necessary to protect the pipeline would have been well above design specifications at high water levels.*

4.26 Further he highlights that:

> *...standard practices in industry, documented by NACE International, ISO, ASTM and other bodies, point out the extra risk of external corrosion of pipelines at landfalls and that special precaution should be taken. Furthermore, it is today standard practice that personnel working with cathodic protection should be certified for the type of work they carry out on pipelines*

4.27 We therefore share Professor Gubner's compelling conclusion that:

> *The incident at Varanus Island on June 3rd 2008 could have been avoided if attention was paid to the inspection reports provided. Apache has continuously been working on the integrity management but the physical work of inspecting the pipelines on the beach crossing of Varanus Island has not been performed accordingly to the routines prescribed by Apache and its consultants. Reading through the different reports and procedures for inspections, it becomes clear that there was no or little effective communication on the subject of pipeline integrity and corrosion protection between the management and the operation. This raises questions about Apache's*

competence to maintain the SGL pipeline. It is also noted that the regulators have not taken notice on the discrepancy between inspection prescribed and inspection that has actually been performed. Last but not least, it is worth pointing out that several contracted inspections and reviews performed by consultants resulted in reports that did not raise a strong concern about the condition of the 12" SGL pipeline at the beach crossing of Varanus Island. It would require a corrosion engineer to pick up on some of the issues raised, but on the other hand, a consultant would expect an expert to read the reports.

Future safety

4.28 In many ways, the precise mechanism for corrosion of the 12 inch SGL is not as important as the need to guard and test against any of these known mechanisms. Given the lack of CP competence and uncertainties noted in this chapter and in chapter 3 we believe that a full expert assessment of corrosion protection systems on Varanus Island needs to be undertaken as a condition of PPA licence PL12.

R 13 **We recommend that as a condition of PL12 licence renewal WA require a full assessment of corrosion protection systems on Varanus Island, including the technical design and operation of cathodic protection at shore crossings with multiple pipelines and possible interference and stray current effects.**

4.29 We are also generally supportive of the other recommendations made by Professor Gubner at the end of Annex 5.

R 14 **We recommend that Western Australia facilitate establishment of a formal technical committee which brings together corrosion expertise from industry, professional associations, regulators and academia with the purpose of promoting best practice in asset integrity assurance. We also support the establishment of a certification system for personnel carrying out cathodic protection services, along the lines of the European or US (NACE) models.**

Conclusions

Technical factors

4.30 The technical data available to us was insufficient to determine the precise causality of the external corrosion on the 12 inch SGL. The four possible scenarios outlined above build on the factors noted in the 7 October 2008 investigation report and key technical factors leading to the 3 June 2008 pipeline ruptures and explosion as a result of external corrosion were:

- Ineffective anti-corrosion coating at the beach crossing section of the 12 inch SGL,
- Ineffective cathodic protection of the wet-dry transition zone of the beach crossing section of the 12 inch SGL, and
- Lack of consideration of potential sources of current that could accelerate corrosion through other pipelines, equipment and structures.

4.31 These scenarios involved mechanisms that were well known in the industry and should have been addressed with an appropriate anti-corrosion system and safety and integrity checking. While there were conflicting opinions within industry about shore crossings and CP efficacy, some initial deficiencies with the 12 inch SGL CP system installed by Hadson, and a gap in the AS2885 standard, these were not substantial in the context of the wide range of material available to Apache over a 14 year period leading up to the 3 June 2008 incident.

Organisational factors

4.32 We covered in chapter 1 the information we felt that Apache could – and should – have assessed in order to ensure the company was engaged in better practice safety management. We also discussed the organisational factors which we consider contributed to Apache's failure to recognise the risks associated with the shore crossing. No doubt, Apache was genuinely surprised by the events of 3 June 2009. Yet despite numerous warning signs and opportunities to recognise the risk associated with the shore crossing area the company failed to act upon the potential risk of corrosion and rupture in this area and therefore failed to investigate and mitigate that risk.

4.33 We consider that key contributing Apache organisational factors to the pipeline ruptures and explosions of 3 June 2008 included:

- Insufficient assessment and inspection of the Varanus Island shore crossing zone and the dangers posed by multiple high pressure gas pipelines in a harsh environment,
- Insufficient attention to duty of care obligations which are fundamental to an operator's responsibility in a safety case regime.
- Minimum levels of in-house manning in safety technical functions which, combined with heavy reliance on contractors, resulted in a degraded ability to recognise, follow-up, and respond adequately to specialist reports and risk warnings.

4.34 Apache's failure to recognise the potential for both it and the industry to learn from the events of 3 June 2008 suggests that the company continues to focus on minimising legal liability instead of using the lessons learned to reduce future risk.

Regulatory factors

4.35 Apache's technical and organisational failings are primary. However, regulators also failed to provide an appropriate level of assurance with respect to the risk posed by the shore crossing. Key regulatory factors that reduced safety assurance with respect to the gas pipeline ruptures and explosions of 3 June 2008 were:

- The existence of a confusing mishmash of jurisdictional, legal, process and regulatory interfaces upon which was overlaid poor relationships among regulators,
- The regulation of Varanus Island under WA legislation (PPA) and a licence (PL12) that was inappropriate for the facilities, and was not consistent with a full duty-of-care/safety case regime,
- A lack of staffing and technical competence within DOIR as the primary regulator and a narrow interpretation of its services role on Varanus Island by NOPSA.

4.36 We have found through our investigation that the regulators could have, and indeed should have, better recognised the risk associated with the Varanus island pipeline shore crossing and Apache's failure to properly manage these risks.

4.37 Of the three regulatory agencies involved DOCEP was the only one to provide timely warnings of the increased risk posed by Apache's failure to provide assurance regarding the 12 inch SGL. NOPSA failed to provide safety assurance on Varanus Island due to its perceived limitations under the services contract and its own restrictions on its legal role.

4.38 On the positive side, NOPSA's recognition of basic flaws, like Apache's submission of a scoping paper in place of a complete validation and its ongoing recognition of poor maintenance and audit practices by Apache was commendable.

4.39 DOIR had the legislated responsibility for safety on Varanus and bears the major share of the failure to recognise and act on the warning signs that Apache's safety management was increasing the risk associated with the facilities. The Department's assessment of the 2002 Vananus Island Hub Safety Case was not strong and failed to recognise its deficiencies in respect of hazards from both sales gas pipelines and the shore crossing more generally

4.40 Overall, we believe DOIR became incapable of properly managing safety regulation in WA. By acting as a post box, the division confused industry and obscured safety enforcement without providing any value add. DOIR was unaware of key documents which could have provided clues that pipeline integrity and safety were not being managed effectively on Varanus Island and there was no organisational awareness evident that DOIR understood that some operators required more regulatory oversight than others.

4.41 Both NOPSA and DOIR were hampered in their safety roles by the legislative and licensing framework under the WA PPA which lacked clarity and was difficult to enforce. Continued use of the PPA to licence the major and complex manned facility on Varanus Island was and continues to be inappropriate.

4.42 It is our earnest hope that safety action based on our recommendations in this report and the others we have made in other contexts, will lead to significant improvement in the safety of the offshore industry in Western Australia and more broadly. We believe that many operators can learn both technical and safety culture lessons from this incident. There is also much that can be done to fully implement and augment a seamless offshore safety case regulatory regime that minimises unnecessary interfaces and maximises regulatory effectiveness.

Annex 1:
Initial October 2008 DOIR/NOPSA investigation report

Final report of the findings of the investigation into the pipe rupture and fire incident on 3 June 2008 at the facilities operated by Apache Energy Ltd on Varanus Island

REVISION STATUS

Rev	Date	Description	Author	Reviewed by
A		Draft	Z Lambert Investigation Team Member B Richardson Investigation Team Member	S Sherman Investigation Team Member
B	11/09/08	Draft	Z Lambert B Richardson	G Guyan
C	12/09/08	Final	Z Lambert B Richardson	S Schubach
C1	07/10/08	Final	Z Lambert B Richardson	G Guyan S Schubach

DISTRIBUTION

	Position	Company
1	Records management	NOPSA – original and controlled
2	Director of Petroleum and Royalties Division	DoIR –uncontrolled copy

1. Executive summary

Varanus Island is situated approximately 100 km west of Karratha. Located on the island are oil and gas production facilities operated by Apache Energy Ltd. A number of facilities are located offshore in the waters surrounding Varanus Island and are connected by subsea pipelines to the production facilities on Varanus Island. Collectively, this complex is operated by Apache Energy Ltd, such that hydrocarbons are fed to the Varanus Island facilities and processed prior to export either via two sales gas pipelines to the mainland, or via a crude oil export line to transit tanker vessels.

On the afternoon of the 3 June 2008, at approximately 13:30, a series of explosions followed by fires occurred at the Apache operated facility on Varanus Island.

At the time of the event, there were 150 personnel at the Apache facility on Varanus Island and a further 16 on adjacent offshore platforms.

There were no reported injuries or fatalities as a result of the explosions and fires.

The explosions and fires were concentrated in an area adjacent to the Harriet Joint Venture (HJV) gas plant, on the NNE beach pipeline corridor, where 6 pipelines in close proximity to each other cross the beach.

The plant was shutdown, isolated and vented. All personnel at the Apache Varanus Island onshore facility were mustered and accounted for. By the evening of 3 June 2008 all personnel were evacuated except a skeleton crew of 14 persons who stayed on the island for monitoring purposes.

The fires were extinguished in the early hours of the 5 June 2008.

Apache oil and gas production related activities on the island are regulated under the Western Australian Petroleum Pipelines Act 1969 (PPA69), which is administered by the Western Australian Department of Industry and Resources (WA DoIR). The WA DoIR initiated an investigation into the events of the 3 June 2008. The National Offshore Petroleum Safety Authority (NOPSA) was requested by the DoIR to assist in the conduct of its investigation of the incident and documented terms of reference for the investigation were prepared.

The investigation found that:

1. The activities on the island prior to the incident can be described as routine. The Apache production plant was being operated as normal, with only routine work being carried out. Some project construction work was being undertaken within

the plant area. There is no evidence that this project work activity had any impact on, or contributed to the incident.

2. There was no evidence of any contemporaneous extrinsic activity contributing to the cause of the incident.
3. Evidence indicates that the immediate cause of the incident was the rupture of the 12” sales gas pipeline at the NNE beach crossing and that the gas released from the ruptured pipeline ignited very soon after the rupture.
4. Evidence to date indicates that the pipe was being operated at a pressure within its design envelope. The rupture occurred due to thinning of the pipe wall due to corrosion of the external surface of the pipe resulting in excessive stresses in the pipe wall.

Evidence indicates that as a consequence of the initial 12” sales gas pipeline rupture and ignition of the gas released, the adjacent Campbell / Sinbad to Varanus Island 12” infield gas pipeline also ruptured and released gas which contributed to the fire. As a result of direct or radiant heat impact from the initial ruptures and fires on the beach, the 16” sales gas pipeline and the 6” Harriet Gas Line also ruptured at the boundary of the HJV plant. In addition, part of the HJV plant was damaged.

Evidence gathered to date indicates that the main causal factors in the incident were:

1. Ineffective anti-corrosion coating at the beach crossing section of the 12” sales gas pipeline, due to damage and/or dis-bondment from the pipeline.
2. Ineffective cathodic protection of the wet-dry transition zone of the beach crossing section of the 12” sales gas pipeline on Varanus Island.
3. Ineffective inspection and monitoring by Apache of the beach crossing and shallow water section of the 12” sales gas pipeline on Varanus Island.

There are aspects of some lines of investigation that have not been settled, principally due to delays by Apache in providing information and delays in forensic testing of pipe samples. In particular:

- Completion and full analysis of the forensic testing of pipe samples;
- Statements from key Apache personnel (Apache on behalf of its key personnel declined requests for interview);
- Identification of specific technical details relating to the cathodic protection of the 12” sales gas pipeline.

These matters may be resolved in due course. However, such resolution is unlikely to significantly change the nature of the findings of the investigation and hence this Report is considered to adequately address the terms of reference of the investigation. It is understood that DoIR will review this Report with a view to considering further action.

The investigation identified that Apache Northwest Pty Ltd and its co-licensees may have committed offences under:

1. *Petroleum Pipelines Act 1969*, Sections 36A & 38(b)
2. *Petroleum Pipelines Regulations 1970*, Regulation 10.

Some findings of the investigation may also constitute non-compliance with pipeline licence conditions.

2. Table of contents

3. Abbreviations

AEL	Apache Energy Ltd
ALERT	Organisation contracted to AEL to investigate the incident on their behalf
CP	Cathodic protection
CS1	Compressor station 1 located on the mainland
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DoIR	The Western Australian Department of Industry and Resources
ERT	Emergency response team
ESD	Emergency Shut Down
ESJV	East Spar Joint Venture
GGT	Goldfields Gas Transmission
HAT	High Astrological Tide
HJV	Harriet Joint Venture
IMMR	Inspection Maintenance and Monitoring Regime
LAT	Low Astrological Tide
m	metre
mm	millimetre
NNE	North-North East
NOPSA	National Offshore Petroleum Safety Authority
OHS	Occupational health and safety
P&ID	Process and Instrumentation Diagram
PL	Pipeline Licence
PMP	Pipeline Management Plan
POB	Persons on board
PPA69	*Petroleum Pipelines Act 1969* (WA)
PRD	Petroleum and Royalties Division of DoIR
P(SL)A 82	*Petroleum Submerged Lands Act 1982* (WA)
PSMP	Pipeline Safety Management Plan
PTW	Permit to Work
ROV	Remotely Operated Vehicle
SDV	Shutdown valve
WST	Western standard time

4. Introduction

DoIR requested NOPSA to provide investigation services under the WA DoIR's direction, in order to investigate a pipe rupture and fire that occurred on 3 June 2008 at the Varanus Island gas processing plant operated by Apache Energy Limited.

The request was made in accordance with the Service Contract in place between NOPSA and the State of WA through the Department of Industry and Resources dated June 2007.

The investigation team comprising a DoIR inspector and two NOPSA inspectors travelled to Varanus Island on 4 June 2008. Upon arrival on the island at 17:30 the investigation team was unable to proceed directly to the incident site as Apache advised that it would be unsafe to do so since small fires were still burning. Apache also advised that it was anticipated that, by the following morning of 5 June 2008, the fires would be extinguished and it would be safe to access the incident site.

The investigation team gained access to the incident site on the 5 June 2008, and commenced the investigation. The investigation team left Varanus Island on 7 June 2008.

The investigation was conducted as per the terms of reference agreed between DoIR and NOPSA (see Attachment 1 for details).

The investigation and its attendant findings were delayed by difficulties experienced in sourcing information and accessing personnel. These matters are further discussed in section 6.3.

In accordance with the terms of reference, the focus of the investigation was to identify:

- Facts and events relevant to the incident
- The likely causes of the incident
- Any actions and omissions by the operator of the Varanus Island facility, or its contractors, leading up to the Incident and during the Incident that may have contributed to the cause of the Incident
- Any potential for injury to persons arising directly from the fire and explosion(s) at the time of the incident

The terms of reference for the investigation did not include:

- assessment of the extent of the damage to the plant, except where directly relevant to the main focus of the investigation
- events that occurred after the incident, except where they were directly relevant to the main focus of the investigation
- actions or omissions by any regulator, in particular the DoIR, regarding assessment of the appropriateness of the DoIR

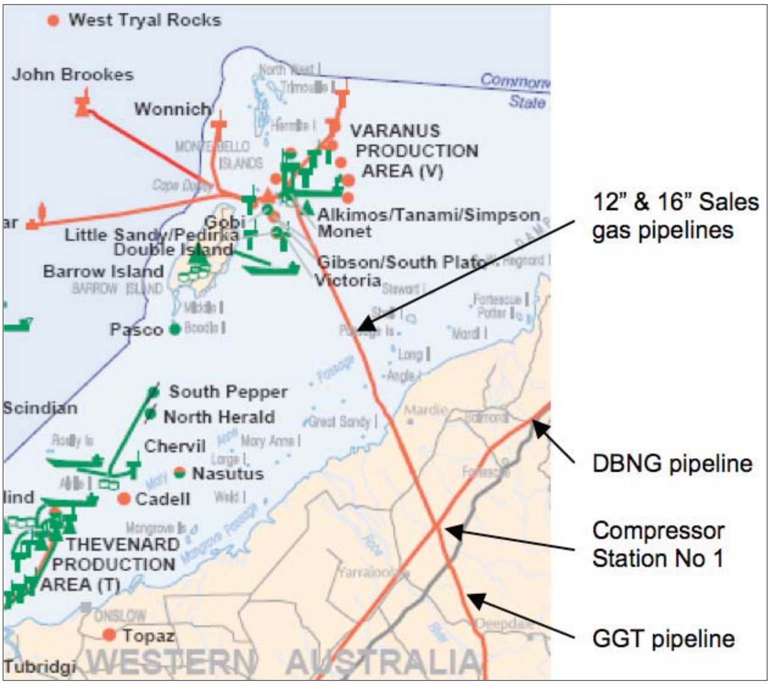
consents and approvals issued to the pipeline licensee with respect to the Varanus Island plant and associated licensed pipelines.

5. Background

5.1 *Location*

The incident occurred at the Apache facilities on Varanus Island which is part of the Lowendal group of islands located to the east of the northern end of Barrow Island (approximately 100 km west of Karratha).

Map 1 – Location of Apache Varanus Island facilities



Apache Energy Ltd operates oil and gas production facilities on and around Varanus Island. Hydrocarbons are piped to the island for processing. After processing, the hydrocarbon products are exported as either gas to the mainland via two subsea pipelines (12" and 16" sales gas pipelines, approximately 100 km long), or as crude oil by tankers from the terminal at the island.

Apache's gas production from its facilities on Varanus Island accounts for approximately 30 per cent of WA gas consumption.

5.2 *Applicable Legislation, Codes and Standards*

The WA *Petroleum Pipeline Act 1969* (PPA69)
This Act regulates the processing and conveyance of petroleum within WA and is applicable to the Apache Varanus Island plant. Pipeline licences were issued by DoIR under this Act to Apache and its co-venturers for the oil and gas production facilities on the island. The relevant licences are:

- PL12 and variations, for the Harriet Joint Venture facilities and associated pipelines onshore Varanus Island including the 12" sales gas pipeline.
- PL 29, PL30 for the East Spar Joint Venture facilities and associated pipelines onshore Varanus Island.

Pipeline licence PL12, held jointly by Apache Northwest Pty Ltd and two other entities, covers the area of the Varanus Island facility affected by the incident. Licence PL12 was granted in May 1985 with 21 years vailidity. An application for renewal of the licence was submitted to DoIR by Apache in December 2005 and has not yet been accepted. In the interim, the PPA69 stipulates that the existing licence remains valid.

Licence PL12 contains a number of specifications and conditions one of which is the requirement for a Safety Case, accepted by the Director of Petroleum and Royalties Division, DoIR, to be in place. The current Apache Energy Ltd Safety Case for the PL12 plant was accepted by the Director, PRD of the DOIR in December 2007.

The Safety Case requirement was first introduced in September 1998, in PL 12 Variation No. 9P/97-8. A safety case is described as 'A document containing information relevant to the identification, assessment, management and monitoring of matters, and other information, relevant to safety in the Licence area'.

The WA *Petroleum Pipelines Act 1969*, as it applies on Varanus Island, is administered by DoIR. NOPSA has provided, on request, technical advice on occupational health and safety matters to DoIR under a contract between NOPSA and DoIR.

The WA *Petroleum Submerged Lands Act 1982* (P(SL)A 82)
The section of the 12" sales gas pipeline directly affected by the incident is located above the low water mark and is outside the jurisdiction of the P(SL)A82. However, the P(SL)A 82 does apply to those sections of the Apache Varanus Island pipelines seaward of the low water mark, and under the WA *Petroleum (Submerged Lands) (Pipelines) Regulations 2007*, consent is required to construct and operate such pipelines. The Regulations require that a person must not undertake construction activities relating to a pipeline unless the WA Minister has consented to the construction

and a pipeline licensee must not operate a pipeline under the licence unless the WA Minister has granted consent to operate the pipeline.

Specifically, pipeline licences were issued by the DoIR under this Act, to Apache Northwest Pty Ltd. and its co-licensees for the offshore sections of certain pipelines. Of the 6 pipelines crossing the NNE beach of Varanus Island, 5 were licensed under this legislation.

The relevant licences are:

- TPL1 for the 8” Harriet crude oil line
- TPL2 for the 30” crude export line
- TPL5 for the 6” Harriet gas line
- TPL8 for the 12” sales gas pipeline
- TPL13 for the 16” sales gas pipeline

The Apache 12” Infield gas pipeline from the Campbell and Sinbad offshore facilities to onshore Varanus Island is not licensed under this legislation. The reason for this is not known to the investigators.

Under the P(SL)A 82 and its regulations, Apache is required to have a Safety Case in force for offshore facilities in these waters. Prior to March 2007, DoIR was the sole regulator of this Act. Subsequently, powers were conferred on NOPSA such that the Safety Case for these offshore facilities must be accepted by NOPSA. In general, the P(SL)A 82 regulating the offshore facilities around Varanus Island continues to be administered by DoIR, with NOPSA administering the regulation of health and safety matters.

The Apache Energy Ltd Varanus Hub Safety Case is currently a combined Safety Case document, encompassing the offshore facilities and the onshore process plant. The Safety Case addresses the requirements of both the P(SL)A 82 and its regulations, and the requirements of the onshore pipeline licences issued under the PPA69 (PL 12, 29 and 30) relating to the onshore process plant. The current Safety Case was accepted in October and December 2007 by NOPSA and the DoIR respectively, each according to the jurisdictions outlined in this paragraph.

Further, effective March 2008, the WA P(SL)Act 1982 and its regulations, requires a licensee of licensed pipelines to have a Pipeline Management Plan (PMP) in force. The PMP must contain information pertaining to the matters described in Part 4 Division 2 of the WA Petroleum (Submerged Lands) (Pipeline) Regulations 2007. The PMP must be accepted by the WA Minister. A Pipeline Safety Management Plan (PSMP), defined as the components of a PMP that provide for the safety and health of persons at or near the pipeline, must be assessed and accepted by NOPSA. The WA Minister may not accept a PMP without NOPSA having first notified the Minister that the PSMP is acceptable.

The Apache Energy Ltd Operational PMP, currently in force for all pipelines operated by Apache on the North West Shelf, was accepted by DoIR under its delegated powers, in March 2008.

Applicable Codes and Standards

The applicable standards for the design, operation and maintenance of pipelines are typically specified in the pipeline licences. For the Apache 12" sales gas pipeline, the licences (PL12 for the Varanus Island section, TPL8 for the subsea section, and PL17 for the onshore mainland section) state that AS2885 – 1987 Pipelines – Gas and Liquid Petroleum (the SAA code), is the applicable standard. Section 13 of this standard deals with operation and maintenance.

This standard was later superseded by AS2885.1-1997, AS2885.2-1995, and AS2885.3-1997. The current versions of AS2885 are:

- AS2885.1 – 2007 Pipelines-Gas and Liquid Petroleum-Design and
- Construction.
- AS2885.2 – 2007 Pipelines-Gas and Liquid Petroleum-Welding.
- AS2885.3 – 2001 Pipelines-Gas and Liquid Petroleum-Operation and
- Maintenance.
- AS2885.4 – 2003 Pipelines-Gas and Liquid Petroleum-Offshore submarine
- pipeline systems.
- AS/NZS2885.5: 2002 Pipelines-Gas and Liquid Petroleum-Field pressure testing.

AS2885.4 – 2003 refers the reader directly to Det Norske Veritas offshore standard DNV-OS-F101 Submarine Pipeline Systems, and disapplies AS2885.1, 2, 3 and 5.

Section 10 of DNV-OS-F101 deals with the operation, inspection and repair of submarine pipeline systems.

The basis of design for the 12" sales gas pipeline, cites the following standards related to the cathodic protection system applied to the pipeline:

- AS/NZS 2832.1: 1986 Cathodic Protection of Metals Part 1 Pipes and Cables and Ducts 1985.
- DNV-RP-B401 Recommended practice for Cathodic Protection Design 1986

6. Investigation activities

6.1 *Activities at the Apache operated facilities on Varanus Island*

The investigation team arrived at the Apache operated facilities on Varanus Island at 17:30 WST on Wednesday 4 June 2008. The investigation team left the island at 12:15 WST on Saturday 7 June 2008.

During the period spent investigating the incident at the island, the investigation team carried out the following tasks and activities:

- Held a meeting with Apache's management and an ALERT representative (an investigator contracted by Apache) to explain the purpose and process of the investigation.
- Viewed a sample of Apache's incident photographs to develop a perspective on the nature of the incident.
- Inspected the incident site, took photographs, made sketches (see Attachment 5 & 6)
- Interviewed and took formal statements from nine people who were witness to the events of the 3 June 2008 and from one person with information relevant to the investigation (listed in Attachment 7). The personnel interviewed provided information about:
    - General conditions and activities at the Apache facilities on the island prior to the incident
    - Their own activities and location within the Apache facilities prior to the incident
    - The sequence of events of the incident
    - Post incident events
    - Their own actions
    - Actions taken by Apache
- Requested and obtained information from Apache (drawings, reports, photographs) Attachment 2, Table 2, identifies documentation received from Apache at site.
- Discussed the manner of removal, transport and testing of samples from selected pipes from the incident site.
- A process by which the integrity of the testing to be carried out by Apache and its contractors could be assured was agreed between DoIR and Apache. This process entailed:
    - Arrangement for the pipe samples to be transported and tested in a manner that would ensure the continuity of evidence. This involved acceptance by DoIR of the transport protocol.

- Verification of pipe samples arriving at the PearlStreet testing laboratory, Welshpool WA, which involved one of the investigators witnessing the unpacking of pipe sample containers.
- Acceptance by DoIR of the non-destructive and destructive test protocol.
- Arranging access to the test results and report.
- DoIR agreement for the destructive tests to proceed after being satisfied that non-destructive tests have been satisfactorily completed.

6.2 *Activities subsequent to site visit of the Apache facilities on Varanus Island*

The investigators identified a number of areas as relevant or potentially relevant, within the scope of the investigation. These formed the basis of the lines of investigation developed and (see Attachment 2 Table 1 for details), they are summarised below:

1. Confirmation of the location of the incident site.
2. Examination of the incident site including external examination of the damaged pipes.
3. Reviewing extent of plant damage.
4. Establishing the number and distribution of personnel at the Apache facilities on Varanus Island.
5. Identifying activities taking place at the Apache facilities on the island prior to the incident.
6. Establishing the operating parameters and status of the Apache production plant and the affected Apache pipelines.
7. Establishing the sequence of events.
8. Examining potential personnel exposure.
9. Identifying post incident events and their relevance to the incident, including:
   - Actions taken by individuals, in particular Apache process operators and supervisors,
   - Immediate response to the incident (personnel musters, incident monitoring and personnel evacuation).
10. Identifying the failure mode of the pipelines, which included review of the pipe sample test results and independent experts reports, so far as available.
11. Identification of applicable legislation, including subsidiary regulatory approvals relating to the Apache pipelines and facilities.

12. Review the relevant pipelines design and protection systems.
13. Examining the adequacy of Apache's pipeline inspection, maintenance and monitoring regime, including past inspection, maintenance and monitoring records for selected pipelines.
14. Identifying pipeline inspection, monitoring and maintenance requirements as stipulated in relevant licences, codes and standards.
15. Resources and structure of Apache's pipeline inspection and maintenance group.
16. Identifying causes of the incident.
17. Identifying possible breaches of legislation.

The following sources of information were used during the investigation (for details see Attachment 2 Table 1 & 2):

- Site visits
- Witness statements taken from Apache staff and its contractor staff
- Pipe inspections and sample test results
- Independent specialist opinions
- Legislation, licences, codes and standards
- DoIR records
- Apache documentation (drawings, procedures, manuals, reports, data).

Over 250 documents, principally Apache documents, (see Attachment 2 Table 2), including several reports and manuals, were examined by the investigating team. This information was provided by Apache after some delay and following reinforcement of DoIR requests. Review of these documents, conducted for the purpose of extracting relevant information, was carried out in parallel with, and informed, the other investigation activities which included:

- Developing the lines of investigation
- Arranging and conducting interviews (16 persons in total were interviewed – Attachment 7)
- Managing information (requesting, receiving and monitoring)
- Liaising with Apache on testing of pipe samples
- Arranging for the engagement of two independent specialists:
    - A metallurgist ; and
    - A pipeline corrosion expert
- Analysing data
- Report writing.

The investigators also reviewed reports (Attachment 2, Table 2, reference item 259) relating to testing of samples of pipelines removed from the incident site. In total, 11 pipe samples were removed from the incident site. Of the 11 samples, four were considered to be of primary importance to the investigation. These were the samples removed from either side of the rupture point on the 12” sales gas pipeline, and from either side of the rupture point on the 12” Campbell/Sinbad pipeline.

As discussed in section 6.1, a testing protocol was agreed by DoIR and Apache, detailing the tests that would be undertaken. These tests were both non destructive and destructive in nature. The tests proposed included:

- Visual examination
- Dimensional assessment
- Surface deposit sampling and analysis
- Ultrasonic examination
- Radiographic examination
- Examination of fracture surfaces
- Crack testing
- Examination of the Metallurgy
- Mechanical testing
- Chemical analysis

At this time, no testing has been undertaken that would permanently alter the pipe samples from their ‘as removed’ condition. Findings from the test results received to date are discussed in section 7.8.

6.3 *Impediments to the Investigation*

Early in the investigation, the investigation team identified the need to interview key Apache personnel about, for example, matters pertaining to the pipeline inspection, monitoring, maintenance, and repair regime.

Requests for interview were declined by Apache.

Apache subsequently agreed to respond to written question sets developed and submitted by the investigation team to the individuals concerned. Apache then advised the DoIR investigator that no responses to written questions would be provided within the investigation time scale. Consequently, the investigators were unable to question the Apache personnel listed below who were considered to have knowledge of matters pertaining to the incident, and potentially able to provide verification of the investigators’ understanding of the events leading to the incident:

- Production Manager
- Senior Integrity Engineer (current and previous occupier of the position)
- Corrosion Technician
- Person in Charge of Harriet A platform

It is noted that the investigation team was provided with a document entitled *'Corporate Response by Apache Northwest Pty Ltd to the Questions posed by the DoIR for the Production Manager, Ivor Alexander'* on 8 September 2008; over seven weeks after these written questions were issued to Apache.

Delays were also experienced in accessing the reports arising from the examination and testing of the pipeline samples removed from the incident site. The initial indication was that all non-destructive and destructive tests arranged through Apache would be completed within eight weeks from the date of the incident. The non-destructive test results were provided to the investigators 11 weeks after the incident. The destructive testing phase, and some elements of the non destructive testing that involve physically altering the pipe samples, have not yet been carried out. At the time of writing, it is estimated that reports on these aspects of the testing will not be available until mid November 2008.

These matters directly impacted on the ability of the investigation team to develop its findings within the agreed time period and resulted in aspects of some lines of the investigation not being fully settled. However, it is considered that resolution of these matters is unlikely to significantly change the nature of the findings of the investigation.

7. Findings

Notwithstanding the difficulties encountered by the investigation team in sourcing information, the following findings have been produced following analysis of the available information.

Each finding is marked with the letter F and a number. Attachment 2, Table 1, provides cross reference between the individual finding and the information source on which the finding is based.

F1. The incident resulted in the shut down of all Apache operated Varanus Island production facilities and connected platforms, including gas export to the mainland.

7.1 Environmental conditions

F2. The environmental conditions on the island on the day of the incident were as follows:

- Wind: East/South East, 10 knots with 12 knots gusts
- Waves: 0.9 m (significant height)
- Visibility: Good

7.2 Sequence of events

7.2.1 Events leading up to the incident

F3. In the hours leading up to the incident the activities at the Apache facilities on the island could be best described as normal and routine. There were no notable production process upsets in the days leading to the incident or immediately prior to the incident on 3 June 2008.

F4. The production plant operated as normal, with no major work outside of routine maintenance activities, being conducted on the day.

F5. Contractors were undertaking project works within the plant areas. New (Mars) compressor installation activities, mainly civil works, were being carried out by Apache contractor personnel approximately 130 metres from the incident site. Tie in pipe spools were being fabricated in advance of a planned shutdown. Appropriate work permits were in place for these works.

F6. At the time of the incident there were 150 personnel on the island and 16 personnel offshore on the Apache Harriet A and Gibson platforms (166 in total).

7.2.2 Sequence of incident events

F7. On the basis of personnel interviews and information provided, the investigation team believes the sequence of events on the 3 June 2008, was as follows:

3 June 08		Harriet Joint venture plant in steady state operation, 12" sales gas pipeline operating at 11100kPa, 16" sales gas pipeline operating at 13200kPa.
•	13:30	12" initial explosion heard (12" gas sales line ruptures followed by 12" Campbell/ Sinbad pipeline).
•	"	ESD initiated in the control room. Plant blow-down commenced.
•	13:50	Muster of personnel completed at two locations (control building and main camp). Large fires observed to north side of Apache HJV plant.
•	13:55	ERT deployed to assess (from a distance) the incident site. ERT deploys 3 water monitors to cool equipment adjacent to the incident site and returns to the main camp.
•	14:00	DBNGP Control Room contacted. Request was made to remotely shut in Compressor Station no 1 (CS1). Following further discussions it was agreed that DBNGP would continue to take gas from Apache to reduce pressure in the 12" and 16" sales gas lines.
•	14:18	BK helicopter and an Apache service boat (Loligo) sent to observe the incident from a distance, take photographs, observe the nature of the incident and damage, and report to the Apache Field Superintendent.
•	14:27	16" sales gas line and 6" Harriet gas line rupture.
•	14:27	Apache control room personnel evacuated to the main camp. Second muster of all personnel completed.
•	14:30	Helicopter departs for the mainland (CS1) to confirm and if necessary isolate the 12" and 16" sales lines (the concern was that the contents of the 16" line could feed through the inter-connector valve to the 12" sales gas line).
•	"	Boat (Loligo) departs the incident site to pick up personnel from Apache Harriet A and Gibson platforms
•	"	Two operators went to the 'A' crude storage tank and closed the inlet valve, to prevent the crude from feeding the fire if the crude export line was damaged / ruptured. The remaining tanks ('B' and 'C') were inactive and isolated prior to the incident.
•	15:00	Meter station at CS1 shut in automatically due to decreased pressure in 12" and 16" sales gas lines – gas flow into DBNGP stopped.
•	15:15	Boat (Loligo) evacuated all 16 personnel from Apache Harriet A and Gibson platforms to the Apache facility muster area at Varanus Island.
•	15:26	Apache personnel sent by Helicopter to CS1 reported that 16" and 12" lines had been isolated manually at CS1.
•	15:50	GGT Control Room contacted by Apache. GGT flow control valves closed.
•	16:02	BK helicopter arrives at Barrow Island (from CS 1).
•		Boat (Loligo) moves towards the incident site to observe the fires from a safe distance.
•	17:10	BK helicopter returned to Varanus Island, evacuation of non-essential personnel commenced.
•	18:00	Boat (Loligo) returned to Varanus Island.
•	18:35	ERT sent to fight small brush fires (returned 19:35).
•	19:41	Last helicopter evacuation flight from Varanus Island, 14 person skeleton crew stayed overnight on the island.
4 June 08	07:00	ERT team deployed to site. Main fires out. ERT extinguish small brush fires.

7.3 *Potential for injury*

F8. In general, personnel visits to the NNE beach are discouraged due to environmental concerns. The beach has little recreational utility. The operational visits are infrequent and short, mainly for the purpose of:

- Inspecting the pipelines crossing the beach, and
- Setting up a suck back pump on the 30" crude export line every time the oil is loaded to the visiting tanker (usually once a month).

F9. After the incident Apache introduced formal instructions preventing unauthorised access to the NNE beach.

F10. Although there were no reported injuries or fatalities, the incident had the potential to result in casualties. The lack of casualties was mainly due to the following factors:

- no personnel were on the NNE beach on the day of the incident,
- no personnel were working in the northern corner of the HJV gas plant adjacent to the incident site. Four people nearest the incident site were working in the HJV gas plant (approximately 110–130 meters away from the point of rupture on the beach); and
- no personnel were using the road on the embankment between the HJV gas plant and the beach when the first explosion occurred.

7.4 *Incident location and layout*

F11. The incident occurred on the pipeline beach crossing (NNE beach) behind the Apache Harriet Joint Venture (HJV) gas plant.

F12. A corridor containing 6 pipelines in close proximity to each other traverses the NNE beach (see Attachment 5, Photos 4a) & 4b).

Looking from the beach towards the gas plant, from left to right, the pipelines are:

Pipe (Licence)	Pipe details	Date installed	Surface/ buried at rupture site.
16" sales gas pipeline variation 9P/97-8 to PL12, TPL13, & variation 10P/97-8 to PL17	75 mm Concrete weight coating 4 mm Asphalt enamel corrosion coating (sub-sea section)	1999, 20 year design life	Surface
6" Harriet to Varanus Island Gas line variation 1/91-2 to PL12 & TPL5	Stabilisation by trenching and mattresses offshore-no concrete weight coating 0.4 mm fusion bonded epoxy corrosion coating	1988/89, 20 year design life	Buried
30" crude oil export line PL12 & TPL2	65 mm concrete weight coating 0.4mm fusion bonded epoxy corrosion coating	1986, 20 year design life	Surface/ partial buried
12" sales gas pipeline Variation 1/91-2 to PL12, TPL8, PL17	25mm concrete weight coating 4.5mm Asphalt enamel corrosion coating (sub-sea section)	1992, 25 year design life	Buried
Campbell/Sinbad to Varanus Island 12" infield pipeline Variation 1/91-2 to PL12	25mm concrete weight coating. 4mm Asphalt enamel corrosion coating	1992, 15 year design life	Buried
8" Harriet to Varanus Island oil line, (PL12, TPL1)	Stabilisation by trenching offshore 0.4mm fusion bonded epoxy corrosion coating	10 year design life	Buried

The six pipelines are unequally spaced.

The smallest separation gap of 167 mm – as measured on 6 June 2008 – was between the 12” sales gas line, the first pipeline to rupture, and the adjacent 12” Campbell/Sinbad line, the second pipeline to rupture (see Attachment 6, Sketch 1).

This separation distance is a contributory factor in the consequential rupture of the Campbell Sinbad infield 12” gas pipeline, following the initial rupture of the 12” sales gas pipeline.

Review of the formal safety assessment section of the Pipeline Management Plan for the pipelines indicated that Apache had recognised this as a potential threat. The document identifies the threat as ‘failure of an adjacent pipeline’. Control measures were identified as being ‘minimum separation between pipelines’, and ‘inspection testing and monitoring of the adjacent pipeline’. The investigators found no information indicating what the minimum separation distance should be. See discussion in section 7.9 with respect to pipeline IMMR activities.

7.5 The Incident

F13. There is no evidence that there were any specific events (e.g. process upsets) immediately prior to the incident, which may have triggered or contributed to the incident.

F14. Four Apache pipelines ruptured during the incident:

- The 12” sales gas pipe line (ruptured on the beach)
- The Campbell/Sinbad to Varanus Island 12” infield gas pipeline (ruptured on the beach)
- The 16” sales gas pipe line (ruptured at the top of the seawall banking)
- The 6” Harriet gas line (ruptured on bend adjacent to 16” SDV 301L).

F15. Prior to the incident, the pipelines which ruptured were being operated by Apache within their design operating pressures and temperatures as shown below.

Pipe	Carried substance	Operating Pressure (kPa)		Operating Temperature (°C)	
		Maximum Allowable	Actual	Maximum Allowable	Actual
12" sales gas pipeline to mainland	Dry sales gas	14500	11100	80	59
Campbell/Sinbad to Varanus Island 12" infield pipeline	Wet gas and produced water	9700	5160	80	n/a
16" sales gas pipeline to mainland	Dry sales gas	20160	13200	70	50
6" Harriet to Varanus Island Gas line	Wet gas and produced water	9900	3570	65	34

F16. The composition of the fluids conveyed in the pipelines on the day of the incident was generally within the range quoted in the PMP; the one exception being the carbon dioxide (CO2) level for the 12" and 16" sales gas lines, which was between 3.2 and 3.6 mol%, above the 3.0 mol% quoted in the PMP and 3.1 mol% stated in the TPL8 licence. Although CO2 is known for its corrosive properties, the increased level of CO2 is not seen as a factor contributing to this incident in view of the identified failure modes of the pipelines.

F17. The first line to rupture was the 12" sales gas line. This finding is based on the following:

- Witness statements taken from control room operators and the investigators' review of control room data provide evidence that immediately following the initial rupture, the pressure reading in the control room on the 12" sales gas pipeline dropped from 11100 kPa to 0. There was no pressure drop indicated on other lines at that time.
- Investigators on-site visual examination and subsequent forensic testing by PearlStreet testing laboratory, Welshpool WA of the 12" sales gas line revealed extensive external corrosion (pitting) and thinning of the pipe wall (from approx 11 mm down to approximately 1.5 mm in a section of the rupture area). The corrosion was observed along the full length of the ruptured section of the pipe, between 2 o'clock and 8 o'clock.

F18. The second line to rupture was the Campbell/Sinbad to Varanus Island 12” infield gas pipeline. This is based on the following:

- Witness statements indicating two explosions were heard initially.
- The close proximity of this line to the 12” sales gas line.
- The investigators’ review of the Varanus Island facility control room data provided by Apache is inconclusive in indicating the time of this second rupture, but does indicate that this line was intact prior to the rupture of the 12” sales gas line.
- The investigators’ visual examination and subsequent forensic testing by PearlStreet, of the Campbell / Sinbad to Varanus Island 12” infield gas pipeline, adjacent to the 12” sales gas line, revealed similar but smaller areas of external corrosion. No other pipes in the vicinity showed similar levels of external corrosion.

F19. The initial explosions occurred on the beach. The nearest elements of the Apache HJV gas plant are located approximately 75m away, but are approximately 5m above the level of the pipelines on the beach. Because of this, the jet fires from the ruptured ends of the 12” pipelines were deflected by the embankment up into the air, and did not impinge directly into the plant areas (Attachment 5, Photos 2 and 3).

F20. The ruptures created a crater on the beach approximately 8m wide x 2m deep x 30m long which exposed the buried pipes (Attachment 5 Photo 5).

F21. No obvious remote source of ignition has been identified. There was no hot work being undertaken near the rupture site at the time, i.e. there was no work, involving for example burning, welding or grinding, directly capable of providing an ignition source.

Potential sources of ignition of the hydrocarbon release include:

- Pieces of ruptured pipes sparking when hitting each other or other objects,
- Stones, pieces of concrete and other debris hitting the HJV gas plant (structure, electrical equipment and cabling) and causing sparks.

F22. As a result of the ruptures, the surrounding areas, including the NNE part of the Apache HJV gas plant, were showered with rocks, smaller stones, gravel, and pieces of concrete stability coating thrown from the pipelines Attachment 5 photo 12 shows the largest rock (17.5kg) found within the Apache HJV plant area. Persons interviewed indicated this rock and other debris, were not present within the plant area prior to the incident.

F23. Based on a review of tests conducted to date by PearlStreet testing laboratory, Welshpool WA on the ruptured pipe samples indicate that:

- The 12” sales gas line ruptured due to a mechanical failure
- The Campbell/Sinbad to Varanus Island 12” infield gas pipeline failed due to the combination of mechanical and heat impact from the 12” sales gas line rupture, explosion and fire
- The 16” sales gas line failed due to heat impact/radiation from earlier fires and explosion
- The 6” Harriet gas line failed due to heat radiation/impact

F24. The 16” sales gas line, failed high on the embankment close to the 16” Shut Down Valve (Attachment 5 Photo 10). Discharge from this line (jet fire) was away from the plant, towards the beach.

F25. The 16” sales gas line SDV valve position indicator in the Apache Varanus Island facility control room showed that the valve was ‘in transit’, suggesting that it did not close properly on activation at the time of the incident. Subsequent examination by Score Pacific concluded that the valve did move to the closed position following the ESD initiation (see Attachment 5 Photo 16). The most likely cause of the ‘in transit’ indication in the control room was a faulty or misaligned valve position indicator.

F26. Following the initial ruptures and fire, three water monitors were activated by the Apache Emergency Response Team (ERT) to create a protective water cooling curtain between the fires and the plant (Attachment 5, Photo 2). This action appears to have been effective in preventing more widespread damage to the Apache HJV gas plant from radiant heat.

F27. At the time of the incident, the prevailing wind was blowing across the pipelines, pushing the flames across the face of the HJV gas plant, not towards it (see Attachment 4 Drawing 2).

F28. The metering station at the mainland compressor station (CS1) shut in automatically due to pressure drop in both 12” and 16” lines. Later, the lines were also isolated manually at this location by Apache personnel sent by helicopter.

F29. The Apache production facilities on the island were isolated and blown down through the elevated flares.

7.6 *Post Incident Events*

F30. All personnel were accounted for within approximately 20 minutes after the incident, and initial muster alarm.

F31. Out of 166 personnel on Varanus Island:

- 152 were evacuated off the island. Of those:
  - 145 were evacuated by helicopters to Barrow Island where they were provided with temporary accommodation. This required 13 helicopter flights by five helicopters (one BK helicopter, two S76s and two Super Pumas).
  - Seven were evacuated by boat to Dampier.
- 14 personnel remained on the island overnight to monitor the situation.

7.7 *Damage*

Four pipelines ruptured during the event (see F14 for details).

F32. There was substantial damage due to fire and heat radiation to the Northern corner section of the Apache HJV gas plant, including the Hot Oil unit, and piping around the pipeline Pig launchers/receivers. This included physical destruction of, or damage to, pipe racks, structures, electrical equipment, vessels, valves and piping (see Drawing 2 in Attachment 4 & photos in Attachment 5).

There was also some damage to the adjacent Apache HJV and ESJV plants from flying debris and heat radiation.

Detailed assessment of the plant damage has not been carried out as part of this investigation as this matter is outside the investigation Terms of Reference (see Attachment 1 for details).

7.8 *Failure mechanism of the 12" Sales Gas Pipeline at Varanus Island NNE Beach Crossing*

The following explanation of the 12" sales gas pipeline failure mechanism is based on the information available to date, which did not include final results and analysis of forensic tests of pipe samples;

Pipe sample examination and testing
At the time of writing, no testing that would permanently alter the pipe samples from their 'as removed' condition, has been undertaken. The testing conducted to date indicates the following:

- 12" sales gas pipeline

  The pipe samples removed from both sides of the rupture point exhibit extensive pitting due to corrosion of the external surface along the entire length of the samples. Pipe wall thickness assessments are continuing, however the results to date indicate that over a significant area, the wall thickness has been reduced from a nominal 11.1mm down to approximately 3mm to 4mm in areas, with some areas immediately adjacent to the rupture point significantly less than that.

The pipe samples removed from both sides of the rupture point are devoid of corrosion coating. It should be noted that the sample removed from the south side of the rupture point was largely exposed by the explosion and was exposed to the subsequent jet fire and heat following ignition of the released gas. The sample removed from the north side of the rupture remained largely buried following the explosion and ignition of released gas and was therefore shielded from the effects of the fire. It is therefore concluded that the corrosion coating originally applied to this pipe section had deteriorated and become dis-bonded prior to the incident occurring, and had not simply burned away.

- 12” Campbell / Sinbad pipeline

  The pipe samples removed from both sides of the rupture point exhibit areas of localised pitting due to corrosion of the external surface. Pipe wall thickness assessments are continuing, however the results to date indicate that, in general, the pipe wall thickness has been maintained.

  Despite being exposed to fire and radiant heat, the pipe sample removed from the south side of the rupture point exhibits what is thought to be corrosion coating residue over intermittent areas of the pipe sample along its full length. This residue is flaking away from the pipe surface. Pitting of the external pipe surface is evident beneath this residue.

  The pipe sample removed from the north side of the rupture point shows no signs of pitting to the external surface, and is devoid of corrosion coating residue. It should be noted that this section of pipe was closest to the adjacent 12”sales gas pipeline and the heat effects from the ignited gas flowing from the ruptured end of that pipe.

Pipeline corrosion

12” sales gas pipeline

In order for corrosion of the external surface of the 12” sales gas pipeline to take place, the corrosion coating must have failed. This coating failure may have been due to incorrect application, damage to the coating either prior to, during, or after installation, or loss of adhesion of the coating during operation. The evidence available to date is insufficient to determine why the corrosion coating may have failed.

F33. The extent and depth of corrosion indicates it is likely that the corrosion occurred over a significant period.

The evidence also suggests that the cathodic protection system was ineffective in providing an adequate level of protection to the section of pipe in the environment where sea water either saturates or drains away from the beach sand (refer photos 14 &15 Attachment 5, and section 7.10).

As a result, due to ongoing external corrosion, the pipeline wall thickness was progressively reduced in a section of the rupture area from the original nominal 11.1 mm down to 1.5 mm (this includes thickness reduction / necking due to material yield).

F34. Although pre-yield wall thickness measurements are not available, the evidence indicates that on the day of the incident the pipe wall was subject to a stress level beyond its minimum yield strength. Progressive metal yield and increase in the pipe diameter raised stresses beyond the ultimate tensile strength of the metal resulting in the catastrophic failure of the pipeline. This occurred under normal process operating conditions (see F. 15)

F35. There is no evidence to indicate that the localised external pitting and resulting loss of wall thickness evident on the pipe samples removed from the beach crossing section of the 12" Campbell / Sinbad pipeline was a factor in this incident.

Apache pipelines IMMR (Inspection Maintenance and Monitoring Regime)

Apache safety case and pipeline management plan

As discussed in section 5.2, the pipeline licence PL12 held by Apache NorthWest Pty Ltd and its co-licensees, in conjunction with the P(SL)A82 and its regulations, require that a Safety Case (SC) be in force for Varanus Island and for the offshore facilities around Varanus Island. Apache has a single safety case document addressing the management of the onshore Varanus Island plant and all of the offshore facilities connected to Varanus Island. This document is known as the Varanus Hub Safety Case. A component part of the Varanus Hub Safety Case is the Safety Management System description (SMS), which describes how safety is managed on these Apache facilities. The safety management system provides for all activities envisaged to be undertaken on these facilities, with a focus on:

- The identification of hazards and assessment of risks to the health and safety of people associated with undertaking those activities;
- The implementation of control measures to reduce the risk to personnel to a level as low as reasonably practicable;

- The ongoing inspection, monitoring and maintenance of control measures associated with these risks.

One of the key elements of the Apache Safety Management System (SMS) is Element 7 'Integrity Management'. This SMS element sets out in general terms, Apache arrangements for inspection, maintenance and monitoring of process facilities, wells and pipelines throughout their lifespan. Apache has an Integrity Policy which sits alongside its Occupational Health and Safety Policy. In order to meet the commitments of these policies, management systems have been developed. These are:

- The Maintenance Management System
- The Corrosion and Inspection Management System
- The Maintenance strategy for safety critical equipment.

In addition to the safety case requirement, the P(SL)A 82 and its regulations require that a Pipeline Management Plan (PMP) be in force for facilities that are pipelines. A component part of the PMP is the description of the management system, which sets out arrangements for managing all pipelines operated by Apache on the North West Shelf. Its primary aim is to ensure that the integrity of the pipelines is maintained throughout their operational life cycle while safeguarding personnel and the environment.

The Apache SC and PMP management systems are supported by a suite of Apache policies, systems, manuals and procedures pertaining to integrity management. Two documents, in particular, set out the specifics of the current framework for inspection, monitoring, maintenance, and repair (IMMR) activities relative to pipelines. These documents are:

- Onshore Pipeline Inspection Manual (AEL Document OP-14-MG-001) and
- Underwater Inspection Manual (AEL Document AE-00-MG-006).

The Onshore Pipeline Inspection Manual is stated to be applicable to the 'onshore' section of the 12" sales gas pipeline. Onshore is defined as being that part of the pipeline between landfall and the pipeline termination or Pig launcher/receiver. The term "Landfall" is not defined; however it is reasonable to conclude that this document is applicable to the section of pipeline on the beach at the Apache facility on Varanus Island at which the rupture occurred, since this area is readily accessible on foot. The cover sheet for this document indicates it was developed in 1997. The most recent revision is Revision 4, issued for use on the 22/3/06. At the time of writing, and on the basis of the information provided by Apache, it is unclear what document was in place and applicable to the onshore section of the 12" sales gas pipeline prior to the creation of the Onshore Pipeline Inspection Manual.

The Apache Onshore Pipeline Inspection Manual states that the philosophy for inspection shall be consistent with that described in the applicable pipeline standard, AS2885.3-2001. The standard states that pipeline surveillance and inspection frequencies shall be based on the past reliability of the pipeline, historical records, current knowledge of its condition, the rate of deterioration of the pipeline and statutory requirements. In lieu of this approach, the Onshore Pipeline Inspection Manual cites that an annual frequency is to be applied. The document describes a typical inspection programme for onshore pipelines:

- Annual topographical survey in surf zone/beach area
- Annual visual inspection of unburied pipework to determine the condition of the coating, general corrosion and physical damage
- Annual cathodic protection (CP) survey to ensure an adequate level of cathodic protection is being maintained at each test post
- Annual line walk checking condition of CP and other marker posts, including the use of gas detector to identify any leaks
- Annual checks on surge protection systems and static earth system.

The Underwater Inspection Manual describes the means by which Apache manages and performs underwater inspection activities on all of its offshore assets. It includes the subsea sections of pipelines. The document describes four different levels of pipeline survey:

- Level I surveys are undertaken using side scan sonar and Remotely Operated Vehicle (ROV). Should a level I survey indicate that damage has occurred, then a level II survey is undertaken.
- Level II surveys are carried out using ROV and comprise a visual and cathodic protection survey. Should significant structural damage be detected then a level III survey should be undertaken.
- Level III surveys are undertaken using ROV or divers to examine specific characteristics of anomalies identified during the level II survey. Any significant damage detected during a level III survey would become the basis for initiating a level IV survey.
- Level IV surveys consist of underwater non-destructive testing of areas based on the results of level III surveys. In addition to this, Intelligent Pigging of the pipeline may be considered to assess the inside condition of the pipeline, and particularly any loss of wall thickness that may have occurred.

The document states that level 1 surveys shall be conducted at least every three years, level II surveys at least every three years, level III surveys after the discovery of suspected defect areas, and level IV surveys as required.

There is no prescribed frequency for undertaking intelligent pig surveys in either the onshore or under-water portions of the pipelines.

Codes and standards

The pipeline licence PL 12 variation 1/91-2 held by Apache NorthWest Pty Ltd and its co-licensees, as applicable to the section of the 12” sales gas pipeline located onshore Varanus Island, states that the pipeline will be designed, constructed, operated and maintained in accordance with Australian Standard AS2885-1987 Pipelines-Gas and Liquid Petroleum (the SAA Pipeline Code). This standard was in force in 1992 when the 12” sales gas pipeline was designed, constructed, installed and commenced operation. This standard has evolved since 1987 such that the current version now comprises 5 parts, each dealing with a specific area. Australian Standard AS2885.3-2001 Pipelines-Gas and Liquid Petroleum Part 3, discusses the requirements for the Operation and Maintenance of pipelines. The requirements of the earlier version and the current version are slightly different.

AS2885-1987 is prescriptive in that it determines the frequency of inspection of the CP system for a pipeline. The standard requires that:

- Surveys of cathodic protection potential shall be made at intervals of not more than 12 months, or where cathodic protection potentials may be affected by stray DC currents, survey intervals of cathodic protection potentials shall be approved. Galvanic anode cathodic protection installations shall be monitored at intervals of not more than 12 months to ensure their operation.
- the efficacy of a galvanic anode cathodic protection installation shall be established within a period of not more than 12 months of its installation. The installation shall be monitored at intervals of not more than five years to ensure operation, but intervals may be shortened during the approach of the end of the design life.

AS2885.3-2001 does not include any prescriptive requirements that dictate the frequency of inspections or surveys for operating pipelines. The standard states that pipeline surveillance and inspection frequencies shall be based on the past reliability of the pipeline, historical records, current knowledge of its condition, the rate of deterioration of the pipe and statutory requirements.

Apache references this later version of the standard in its Onshore Pipeline Inspection Manual.

Pipeline licence

Apache is also required to comply with the prescriptive requirements for pipeline inspection, maintenance, monitoring and reporting set out in the relevant pipeline licences. For the section of the 12” sales gas pipeline located onshore Varanus Island, the relevant licence is PL12 variation 1/91-2.

PL 12 variation 1/91-2 states that:

- The licensee shall be responsible for installing and monitoring the cathodic protection test points.
- The licensee shall, when required, submit to the Director a report in writing outlining the results of the corrosion surveys and the details of any resulting action by the licensee.
- The licensee shall carry out an annual external survey of the pipeline after the cyclone season and the results of the survey shall be submitted to the director in writing.

There are no other prescriptive requirements relevant to pipeline inspection or surveys within this licence variation.

7.9.1 Apache resources and organisation

Element 1 in the SMS section of the Apache Energy Ltd. SC and PMP outlines the personnel responsibilities and organisational arrangements within Apache.

Whilst the Apache Managing Director has the overall responsibility for Apache operations on Varanus Island, the Apache Production Manager has the responsibility for the implementation of Apache’s integrity policy, including the implementation of the pipeline inspection and corrosion management measures.

Based on a review of Apache documents, two senior engineers report to the Production Manager. These are:

- The Senior Integrity Engineer; principally responsible for the identification, implementation and maintenance of the facilities (including pipelines) corrosion and inspection activities, condition monitoring and recommendation of remedial actions. Key responsibilities include:
  - Corrosion Risk Assessment
  - Development and maintenance of the inspection plans
  - Scheduling and planning of intelligent Pigging activities
  - Development of procedures and instructions relating to corrosion and inspection activities
  - Analysis of results, assessment of anomalies and recommendation of corrective actions.

- The Senior Corrosion Engineer; principally works in coordination with the Senior Integrity Engineer in areas of corrosion monitoring, coating and materials selection. Notable responsibilities include:
  - Development of corrosion monitoring obligations based on all known hazards
  - Recommendation regarding materials selection for repairs, replacement and additions to facilities,
  - Management of coatings, including selection of systems, monitoring and repair.

Other personnel in the integrity management group include:

- Subsea Engineer
- Field Superintendent and
- Support personnel and contractors.

The organisational structure applied to facility integrity management is shown in detail on page 8 of the Apache Integrity Management and Competencies Description Doc No AE-91-IO-001, Rev 0, issued January 2008. The investigators were unable to establish, on the basis of the information provided by Apache, whether:

- There are present incumbents of all positions and
- Which positions are held by Apache employees and which by contractor company employees.

On the basis of the available information, the investigators were unable to determine whether the level of resources (historically and at the time of the incident) provided by Apache was adequate, and whether it was a factor which contributed to this incident. In particular, no information was produced by Apache or found by the investigators that demonstrated the adequacy of the provided resources (personnel, finance and material) and how the required level of resources was maintained over time.

The investigators noted, however, that the Lloyd's Register report titled 'Apache Energy Limited, PL12 Validation Summary Report May 2006 – April 2007' dated 10 May 2007, states on page 14:

> *It was observed that manning levels, at Apache, in various disciplines, are low with key competencies contracted out and / or residing with specific individuals.*

F36. Apache's management of personnel resources and organisational responsibilities for pipeline integrity management may have been a contributory factor in the incident.

7.9.2 Apache's use of contractors

Apache makes use of large and small contractor companies including individual consultants to fulfil resource needs in areas where its in-house expertise is limited or unavailable. The use of contractors extends to pipelines (installation, inspection, monitoring and assessment) and involves:

- Corrosion monitoring, chemical and cathodic protection contractors;
- Pigging contractors;
- Integrity and pipeline engineers;
- Corrosion experts and coating contractors
- Diving contractors
- ROV and side scan survey contractors
- Inspection contractors and Certifying Authorities (e.g. Lloyd's, ABS or DNV).

Apache has a number of systems and procedures for the management of contractors. These include:

- 'Assurance of contractor safety management' (Doc. No. AE-00-ZF-037)
- 'Procedure for preparation and approval of contractors for service' (Doc. No. AE-91-IQ-030 Rev C)
- 'Procedure for mobilising contractors to site' (Doc. No. AE-00-ZF-012).

Since the commencement of Apache operations at its Varanus Island facilities a number of specialist companies have been contracted by Apache to carry out inspections, surveys and assessments, relating to the integrity, including inspection and maintenance arrangements, of the Apache operated pipelines at or connected to the Apache facilities at Varanus Island.

Whilst the reports issued by Apache's contractors have often contained recommendations for improvement, their general conclusions with respect to the condition of equipment (i.e. the pipeline) and how its integrity is managed are positive. Some example comments from such reports are:

- Sales Gas line 5 year integrity review SP-14-RL-067, May 2007, by Subsea Developments:

  There are no findings from the integrity management processes performed for the sales gas pipelines that provide any reason for any changes to the ongoing IMR activities that are not already being addressed in the current risk assessments and anomaly tracking and close out practices

  The AEL Pipeline Integrity Management process is generally following the requirements of AS2885 and any specifics included in the pipeline license for the Sales Gas Pipelines.

- Lloyd's Report titled 'Apache Energy Limited, PL12 Validation Summary Report May 2006 – April 2007' dated 10 May 2007 states on page 2:

  > *Provisions were found to be in place with continuous improvement process to ensure safety of the operational phase and technical integrity for ongoing operations of the Varanus Island whole plant and facilities covered by PL12 as fit for purpose for the next 21 years*

  and on page 7:

  > *based on preliminary review from initial information gathering and gap analysis, the operation was considered to be covered by a comprehensive integrity management system, sufficient to validate operation for approval for pipeline licence revalidation for the next 21 years.*

Broad statements such as these may have been based on limited information, and not on a comprehensive physical inspection of equipment, or a review of all aspects of its operation, inspection, maintenance and repair.

This is particularly relevant to the 12" sales gas pipeline, with one documented inspection by a contractor of the Varanus Island shore crossing section carried out since its construction in 1992.

F37 In general this investigation found that the link between source data and conclusions in the reports were unclear. Apache apparently used these reports as a basis to plan the inspection, maintenance and repair activities of its pipelines and to assure itself and the regulator that the pipelines were safe to operate.

7.9.3 Apache 12" sale gas pipeline IMMR

The investigation team requested from Apache all records of inspection, monitoring, maintenance and repair activity documentation related to the 12" sales gas pipeline, since the commencement of operations in 1992.

Following a review of the documentation provided, the investigation team compiled an IMMR summary table detailing the activities undertaken, when they were undertaken, and importantly, to what part of the 12" sales gas pipeline the activity applied. This chart is included as Attachment 8 Table 1.

This was then compared against those activities that Apache was required to undertake, either by their own documentation, relevant standards, or by conditions in the applicable pipeline licences held by Apache NorthWest Pty Ltd. and its co-licensees. These requirements are summarised in a similar table included as Attachment 8 Table 2.

The investigation team found that:

F38. Variation 1/91-2 to PL 12 (the pipeline licence applicable to the onshore Varanus Island section of the Apache 12” sales gas pipeline) states that the licensee shall carry out an annual external survey of the pipeline after the cyclone season and the results of the survey shall be submitted to the Director in writing.

From the information provided, regular annual external surveys of the section of the pipeline onshore Varanus Island did not occur. It is recognised that surveys of subsea and mainland sections of the pipeline have occurred. However, in the period 1992 to 2008, there were two documented visual inspections of the section of the pipeline onshore Varanus Island. It is unclear whether the results of these reports were provided to the Director, PRD of DoIR as required. These surveys are detailed in the following documentation:

- Varanus Island Ultra shallow water and onshore pipeline inspection, OP-14-RU-002, performed in October 2004.
- 2007 Onshore Pipeline Inspection workbook, Sept 2007.

The ultra shallow water and onshore pipeline inspection in 2004 was undertaken by a contractor to Apache, Netlink Inspection Services. The report highlights 10 anomalies, one of which pertains to the 12” sales gas pipeline. This anomaly related to an area of missing weight coating at pipeline location KP69.703. Apache has provided no information indicating what action was proposed or taken to rectify this anomaly. Shortly after the incident on 3 June 2008, it was noted that this anomaly was still present and apparently degenerated since 2004.

The 2004 report also indicates that there were areas of corrosion and damage on the onshore section of the pipeline however these were apparently not significant enough to be categorised as anomalies in the report. No cathodic protection readings for the 12” sales gas pipeline were taken during this inspection.

The 2007 Onshore Pipeline Inspection Workbook is a record of Apache inspections as required by the Apache Onshore Pipeline Inspection Manual for a number of pipelines located onshore Varanus Island, including the 12” sales gas pipeline. The workbook includes a completed, pipeline general visual inspection record sheet for the Apache 12” sales gas pipeline. A single CP reading is provided. No anomalies are recorded. However, it is noted that a significant proportion of this onshore section is buried, and hence inaccessible for external visual inspection unless excavated. Excavation of the Agincourt pipeline appears to have been undertaken in 2007 according to the Onshore Pipeline Inspection Workbook for that year. It is not clear from the inspection report whether this excavation was for inspection purposes or for remedial works.

A review commissioned by Apache in 2004 highlighted the lack of pipeline inspection data from the shore crossing zones on Varanus Island.

Review of Apache Energy Pipelines 2004, SP-14-RF-003.01/03, by QCL International cites:

> *In general it was found that very little inspection data was available for onshore pipeline sections on Varanus Island, shore sections and subsea risers.*
>
> *The onshore pipelines on Varanus Island are monitored visually during standard operations on the island and inspection data is therefore often not documented. It is also recommended that the inspection procedures for offshore and onshore inspections should be modified to ensure that the offshore section is inspected during HAT, and the onshore section is inspected during LAT, ensuring sufficient overlap*
>
> *At present the shore zones do not seem to be included in either of the standard inspection work scopes*

F39. Variation 1/91-2 to PL 12 (the pipeline licence applicable to the onshore Varanus Island section of the 12" sales gas pipeline) states that the licensee shall be responsible for installing and monitoring the cathodic protection test points. The licensee shall, when required, submit to the Director a report in writing outlining the results of the corrosion surveys and the details of any resulting action by the licensee.

From the information provided, monitoring of the cathodic protection system onshore Varanus Island occurred in 2004, 2006, 2007 and 2008. Records of these inspections are detailed in:

- Offshore pipelines-onshore section cathodic protection survey August 2004, OP-14-RU-003
- VI Offshore pipework monitoring 18/6/06
- VI Offshore pipework monitoring 18/6/07
- 2007 Onshore pipeline Inspection workbook, Sept 2007
- VI Offshore pipework monitoring MCC building 2008.

The investigation team were unable to find any evidence of the Director, PRD of DoIR requiring any reports outlining the results of the surveys.

F40. The Apache Onshore Pipeline Inspection Manual is applicable to the section of the 12" sales gas pipeline located onshore Varanus Island.

This document indicates that a typical inspection programme for onshore pipelines comprises:

- Annual topographical survey in surf zone / beach area

- Annual visual inspection of unburied pipework to determine the condition of the coating, general corrosion and physical damage
- Annual cathodic protection (CP) survey to ensure an adequate level of cathodic protection is being maintained at each test post
- Annual line walk checking condition of CP and other marker posts, including the use of gas detector to identify any leaks
- Annual checks on surge protection systems and static earth system.

From the evidence provided to the investigators by Apache, no annual topographical surveys of the pipeline in the surf/beach zone area were undertaken. As discussed above, visual inspections of the pipeline were undertaken on two occasions, 2004 and 2007. Also as discussed above, cathodic protection readings from the 12” sales gas pipeline in the beach crossing area were taken in 2004, 2006, 2007, and 2008.

F41. From the information provided by Apache, it appears that Apache did not undertake any maintenance or repair activities on the section of the 12” sales gas pipeline onshore Varanus Island since its installation in 1992.

F42. On the basis of the information provided by Apache, an appropriate documented regime for pipeline inspection, maintenance, monitoring and repair is in place, and this regime is consistent with that required by the relevant standards and the requirements of the pipeline licence. However, the available evidence indicates that some aspects of these systems and processes may not have been rigorously implemented since the pipeline was installed in 1992.

7.10 Apache 12” sales gas pipeline and cathodic protection system design

The 12” sales gas pipeline was designed and constructed in accordance with AS2885-1987. The following table summarises key design parameters for the 12” sales gas pipeline.

Pipeline	
Outside diameter	324 mm
Maximum allowable working pressure	14500 kPa
Wall thickness	11.1 mm
Design temperature	10–80° C
Material	API – 5L X60
Minimum yield strength	413 MPa
Corrosion coating	4.5 mm Asphalt Enamel
Corrosion allowance	3 mm
Weight coating	25 mm
Substance to be conveyed	Natural gas (as specified in the PL12 and TPL8)
Design Code	AS 2885
Year installed	1992
Design life	25 Years
CP System	
Design Code	AS2832
	Bracelet anodes – offshore section only

The Apache Pipeline Management Plan, document SP-90-RL-002, is applicable to the full length of the 12” sales gas pipeline. The PMP provides a detailed description of the 12” sales gas pipeline. All significant pipeline accident events for the pipeline are identified and assessed. Mitigation measures are identified to reduce the risk of significant pipeline accident events to a level that is as low as reasonably practicable.

The formal safety assessment section of the PMP identifies external corrosion as a hazard to the 12” sales gas pipeline in the subsea, shore crossing and onshore sections of the pipeline. For the onshore section, external corrosion is assessed as being of medium risk. At the shore crossing and subsea sections, external corrosion is assessed as being of low risk.

For each hazard, physical and procedural preventative or mitigation measures, are identified as follows:

Protection measure	Onshore section	Shore crossing section	Subsea section
Physical protection measure - Anti corrosion coating	Applicable	Applicable	Applicable
Physical protection measure - Cathodic Protection system		Applicable	Applicable
Procedural protection measure -Inspection testing and monitoring, including IP survey	Applicable		
Procedural protection measure-Inspection testing and monitoring, including ROV/IP survey		Applicable	Applicable

From the above it can be seen that Apache has identified two physical barriers against external corrosion of the pipeline for the shore crossing and subsea sections of the pipeline.

However, only one physical protection measure is identified for the onshore section, this being the anti corrosion coating. Inspection testing and monitoring is cited as a procedural barrier. The drawings included in the PMP indicate that the onshore Varanus Island section of the 12” sales gas pipeline is not considered to be protected by a cathodic protection system.

In practice however, based on the nature of CP readings being taken and other factors, it appears that Apache considered that the cathodic protection system in place and active on the subsea and shore crossing sections of the 12” sales gas pipeline, carries over onto the Varanus Island onshore section and provides some protection against corrosion.

In order for corrosion to take place, the anti-corrosion coating must fail, either due to mechanical damage or loss of adhesion. The evidence available to date is insufficient to determine why the corrosion coating may have failed.

F43. Based on examination of samples of the ruptured pipelines by PearlStreet Testing Laboratory, Welshpool WA and the investigators, the anti-corrosion coating at the beach crossing was ineffective due to mechanical damage or loss of adhesion resulting in dis-bondment from the pipe.

The CP system's role is to prevent corrosion if the first barrier, the corrosion coating, has failed.

The key elements of the system are sacrificial anodes attached to the pipeline. In this configuration the generated currents flow from the anodes through the sea water (electrolyte) to the pipeline. Areas which the current leaves are corroded (sacrificial anodes). Areas where the current enters (pipeline) are protected.

The effectiveness of the CP system is dependent on the ability of the current to flow between the anode and the pipe. Subsea, current will flow freely through the seawater medium. However, at the beach crossing section the ability of the current to flow is affected by the environmental conditions. At the beach crossing section the pipeline was buried in sand which was either saturated with, or drained of, sea water, dependent on tidal movements. This results in fluctuations in sand resistivity, with drained sand having higher resistivity affecting the CP current flow. To counter this effect, more negative CP potentials are needed. Such potentials were not available for the beach crossing section from the offshore bracelet anodes. There were no other (onshore) anodes installed to provide cover for this section of the pipe.

F44. On the basis of the available evidence, no aspects of the design of the 12" sales gas pipeline have been identified (excluding the CP system), which contributed to this incident.

F45. The available evidence indicates that the design of the CP system for the offshore section of the 12" sales gas pipeline, would not offer sufficiently negative potentials to protect the wet / dry transition section of the beach crossing of the Apache 12" sales gas pipeline located on Varanus Island.

8. Conclusions

The following conclusions are drawn by the investigation team based on the evidence available to date.

The information gathered during the investigation was examined using the TapRoot® root cause analysis technique. The event analysis chart developed by the investigation team (Attachment 9) shows the sequence of events, existing conditions and causal factors.

8.1 Immediate cause of the incident

The immediate cause of the incident was the rupture of the Apache 12” sales gas pipeline due to excessive stresses in the pipe wall.

Thinning of the pipe wall as a consequence of extensive external corrosion of the pipe resulted in excessive stresses culminating in rupture of the pipe at the beach crossing at the Apache facility on Varanus Island.

8.2 Main causal factors

The main causal factors of the incident were:

1. Ineffective anti-corrosion coating at the beach crossing section of the Apache 12” sales gas pipeline, due to damage and/or dis-bondment from the pipeline.
2. Ineffective cathodic protection of the wet / dry transition zone of the beach crossing section of the Apache 12” sales gas pipeline on Varanus Island.

This is because:

   a) Sufficiently negative cathodic protection potentials required to provide effective cathodic protection in sandy environment were not available from the existing offshore bracelet anodes,

   b) No onshore anodes were installed on the onshore/beach section of the pipeline.

3. Ineffective inspection and monitoring by Apache of the beach crossing and shallow water section of the Apache 12” sales gas pipeline on Varanus Island.

   This is because:

   a) The external corrosion problem was not detected and addressed at this location, although the available evidence indicates that the corrosion progressively affected the pipe over a period of 15 years or more until the pipeline failed.

b) The technique used to take cathodic protection readings to monitor the operation of pipeline protection was inappropriate for the environment in which the readings were taken as it did not allow for the effect of changing resistivity in the wet and dry sandy environment. The limited cathodic potential measurements taken suggested to Apache personnel that the pipeline was adequately protected, which was not the case.

c) Although the Apache 12” sales gas pipeline was built in 1992, there is a lack of historical documentary inspection data related to the Varanus Island onshore section of the 12” sales gas pipeline, with evidence limited to:

- One ultra shallow water and onshore pipeline inspection undertaken in 2004. This inspection covered the onshore beach section of the pipeline but did not comment on the buried sections of pipeline.
- One documented general pipeline inspection undertaken in 2007. This inspection covered the onshore beach section of the pipeline but did not comment on the buried section of pipeline.

d) The Apache inspection regime did not specifically address the transition section between the subsea and shore crossing sections of the pipeline, by for example undertaking inspections at both HAT and LAT to ensure full inspection coverage in this area.

8.3 *Other factors*

The following factors were also found to be relevant to the incident:

1. No Intelligent Pig inspection of the 12” sales gas pipeline was carried out since the pipeline was constructed in 1992. Although this is not a prescribed requirement, such an inspection could have led to the prevention of the incident occurring as it would have detected the pipeline wall thickness metal loss at the Varanus Island beach crossing.

   In response to specific questions from the investigators on this matter, Apache stated in a letter (‘Corporate Response by Apache Northwest Pty Ltd to the Questions posed by the DoIR for the Production Manager, Ivor Alexander’) dated 8 September 2008 that:

   > *In 1998, there was some discussion by a consultant of whether pigging might be done on the 12” line, with a focus on the mangrove area of the mainland side of the line. The suggestion was not adopted.*

This statement may be referring to the Apache commissioned QCL International Corrosion risk assessment of certain pipelines and plant equipment, undertaken in 1997/8. The resulting report, LTS, Sinbad, Campbell and Compressor Station 1 Corrosion Risk Assessment and Inspection Scheme, HE-00-MN-003 Rev 1 issued Sept 1998, considered the risks of internal and external corrosion to the 12” sales gas pipeline.

The report states that that the risk to the pipeline from internal corrosion is minimal.

The report also states that the pipeline is protected from the risks from external corrosion in the subsea section, as long as the mitigation measures in place, i.e. the corrosion coating and cathodic protection system, are monitored, maintained and inspected.

However, the report does recognise that there is a significant risk to the pipeline due to external corrosion in the coastal and onshore sections. Section 7.5 of the report states:

> *The onshore section, particularly in the coastal mangrove areas, is less certain. Variation in local soil conditions means that the current requirement for full protection varies considerably. The location and conditions mean that close interval potential surveys are difficult, and so detailed checks for adequate potential in all areas are not currently performed.*
>
> *Coastal mangrove waters are more aggressive towards coatings and require higher polarising currents than open, deep cold seawater. The combination of warmer conditions, biological activity and tidal effects, mean that the coastal section is more at risk of external failure than any other part of the pipeline. Therefore it is important that cathodic protection surveys be carried out.*

The report discusses the intelligent pigging option:

> *The requirement for intelligent pigging on this line is dictated by the external corrosion hazard, particularly in the coastal mangrove section of the line. The most serious risk to the continuing integrity of the pipeline is where the coating has disbonded, creating a region of wet, bare metal shielded from corrosion protection current. Corrosion may occur despite adequate cathodic protection potentials. This is a risk on all coated pipelines, but is most significant on onshore/inshore lines, particularly under tube wraps and shrink type field weld coatings. The only methods of detecting such failures are either to excavate all field joins, or to run an intelligent pig.*

The report concludes:

> *The economic and safety consequences of a failure of the sales gas pipeline, coupled with the difficulty of surveying the coastal section, and the risk of coating disbondment failure mean that regular intelligent pigging of the line is justified. To save cost, this survey may be concentrated on the coastal and onshore sections of the line. The period is arbitrary – a figure of 5 years is suggested, meaning that an intelligent pig run will be necessary next year. Further surveys will be required depending on the results.*

Whilst the report does not specifically mention the Varanus Island beach crossing section it is clear that Apache was made aware of significant external corrosion risks to the coastal and onshore sections of the pipeline.

Apache provided no explanation as to why the recommendation to conduct Intelligent Pigging to survey / monitor the pipeline for external corrosion, was not followed.

2. It is noted that an Intelligent Pig inspection of the 12" sales gas line was scheduled to be conducted subsequent to the repair works carried out as a result of the incident on 3 June 2008.

3. Close proximity of the pipelines to each other in the beach crossing zone on Varanus Island was a factor in the escalation of the event.

9. Possible breaches of legislation

The investigation identified the following sections of legislation within the Petroleum Pipeline Act 1969 where possible breaches may have occurred:

Section 36A: Work Practices

A licensee shall operate the pipeline specified in the licence of which he is the registered holder in a proper and workmanlike manner and shall secure the safety, health and welfare of persons engaged in operations in connection with the pipeline

Section 38b: Marking of Pipeline and maintenance etc. of property

A licensee-

(b) shall maintain the pipeline in good condition and repair; and

The investigation also identified the following section of legislation within the Petroleum Pipelines Regulations 1970 where possible breaches may have occurred:

Regulation 10: Pipeline Construction and operation requirements

The construction and operation of a pipeline shall be carried out-

(a) in a proper and workmanlike manner;

(b) in accordance with good pipeline construction and operation practice; and

(c) in such manner as to ensure the safety health and welfare of persons engaged in the construction or operation

Some findings contained in this document may also constitute non-compliance with pipeline licence conditions.

10. Attachments

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Attachment 1

Investigation into pipeline rupture and fire on Varanus Island which occurred on Tuesday, 3 June 2008

TERMS OF REFERENCE

Investigation to be undertaken by DoIR /NOPSA Investigation Team – 9 July 2008 (revised)

BACKGROUND

Western Australia's Department of Industry and Resources is assessing the damage at the Apache Varanus Island facilities, which are licensed under the Petroleum Pipelines Act 1969 (PPA1969) as PL12 and/or the *Petroleum (Submerged Lands) Act 1982* as TPL 8.

The Department of Industry and Resources is responsible for regulating the safety and integrity of facilities on Varanus Island under the Petroleum Pipelines Act.

The Department has been administering these responsibilities with input from the National Offshore Petroleum Safety Authority (NOPSA) under a service level agreement and other sources.

The Department has authorized an investigation into the incident which is currently being undertaken by a team consisting of two NOPSA representatives and one departmental inspector appointed under the Petroleum Pipelines Act.

The "Incident" means the failure of pipelines on the NNE beach approach and the resultant explosions and fire.

PURPOSE

The purpose of the investigation is to:

1. Fulfil the request from the Director, PRD of DoIR on 4 June 2008 to assist in the conduct of an investigation under the terms of the Service Contract dated 6 July 2007 between WA DoIR and NOPSA.
2. Gather information and interview people in a manner that does not compromise potential legal action. (This to be achieved through the direction of the WA DoIR representative on the investigation team).
3. Identify the facts and events relevant to the Incident.
4. Identify the likely cause(s) of the Incident.
5. Identify potential breaches of legislation based on the legal advice and direction provided by DoIR.
6. Formally gather evidence consistent with the requirements of DoIR as advised by the investigation team DoIR Inspector.

SCOPE

The investigation will endeavour to address:

1. The pertinent sequence of events on Varanus Island during the Incident.
2. The likely cause(s) of the Incident.
3. Any actions and omissions by the operator of the Varanus Island facility, or its contractors, leading up to the Incident and during the Incident that may have contributed to the cause of the Incident.
4. The identification of any potential for injury to persons arising directly from the fire and explosion(s) at the time of the incident.

The investigation will be conducted in the context of, and will have regard to, good industry practice, the commitments made by the operator in respect of its operation of the Varanus Island facilities and in the context of the applicable laws and licence requirements as detailed to the investigation team by DoIR.

The investigation will **not** address:

- Events that occurred after the incident except where they are directly relevant to items 1–4 of the scope detailed above.
- Assessment of the damage to facilities on the island except where directly relevant to the scope detailed above.
- Adequacy of the arrangements for repair and re-instatement of damaged plant and equipment.

REQUIREMENTS

DoIR may need to require or provide for certain matters pertaining to the investigation. These include:

1. Obtaining information from the Operator and other parties that is considered by the investigation team to be required to assist the investigation.
2. Exercise of powers under the WA Petroleum Pipelines Act 1969.
3. Engagement of independent experts relating to, for example, metallurgy and corrosion mechanisms.

DELIVERABLE

On completion of the investigation, the team will provide a Report to the Director, PRD of DoIR detailing the findings of the investigation.

FURTHER SUPPORT

Officers of NOPSA will work with the Director, PRD to review the Report and provide assistance in the consideration of potential enforcement action or prosecution, meeting with the SSO as appropriate.

Attachment 2

Table 1 - Lines of investigation

No.	Area covered	Information source	Report finding or section (Ref. No.)	Table 2 Information Log (Item. No.)
1	Incident location	• Site visit by investigators • PL 12, TPL 8 • Apache documents (maps and drawings)	F11, F12, F18, F19, F21, F23, F24	5, 53, 54, 56, 57
2	Personnel, number and distribution, on Varanus Island and adjacent offshore platforms on 3 June 2008.	• Apache documents (POB records for VI and offshore platforms) • Apache active work orders and permits (PTW • Witness statements	F5, F6, F10	1-4, 5, 8, 38, 40-44, 54, 46, 62, 63, 64, 68, 69, 71, 72, 75, 114, 231
3	Plant operation on Varanus Island on 3 June 2008 prior to the incident (shut down sections).	• Apache control room data • Apache P&IDs • Witness statements	F3, F4, F5, F21	1-4, 38, 40-42, 47-50, 68, 69, 71, 72, 75, 81-83, 114, 198-206
4	Operating parameters for pipelines on the NNE beach on 3 June 2008, prior to the incident (pressures temperatures, composition of carried fluids)	• Apache control room data • PL12 & TPL8 • PMP • Witness statements	F13, F 15, F16	2, 3, 38, 47-50, 63, 198-206
5	Activities/jobs carried out on Varanus Island prior to the incident	• Apache active work orders and permits (PTW) • Witness statements	F3, F5, F10, F13, F21	1-4, 7, 8, 38, 40-42, 62, 63, 68, 69, 71, 72, 75, 114
6	Environmental conditions on 3 June 2008	• Apache document (weather forecast) • Witness statements	F2, F21, F23, F27	1-4, 38, 40-42, 52, 61, 63, 68, 69, 71, 72, 75, 114
7	Sequence of events on 3 June 2008	• Apache control room data • Helicopters movement log • Pipelines non-destructive and destructive test results • Pipelines inspection and monitoring records • Pipeline corrosion and metallurgical expert reports • Witness statements	F1, F7, F14, F17, F18, F24, F25, F 26, F28, F30	1-4, 38, 40-42, 47-50, 55, 59, 62, 63, 65, 68, 69, 71, 72, 75-83, 93, 113-117, 198-209

No.	Area covered	Information source	Report finding or section (Ref. No.)	Table 2 Information Log (Item. No.)
8	Personnel visits to the NNE beach	• Witness statements	F8, F9, F10	1-4, 38, 40-42, 63, 68, 69, 71, 72, 75, 114
9	Apache procedures/ standing orders regulating access to the NNE beach	• Apache documents • Witness statements	F9	1-4, 38, 40-42, 63, 68, 69, 71, 72, 75, 114, 119
10	Use of the road on the embankment (between the gas plant and the beach) by personnel	• Apache documents • Witness statements	F10	1-4, 38,40-42, 63, 68, 69, 71, 72, 75, 11, 119
11	Personnel exposure during incident	• Apache documents (personnel distribution records, emergency response, VI drawings) • Site visit by investigators • Witness statements	F10, F19	1-4, 5, 8, 38, 40-42, 53, 54, 57, 63, 68-69, 71, 72, 75, 114,
12	Tanker offloading frequency	• Apache documents (tanker visits log)	F8, F10	90
13	Setting up up/testing of crude export line suck back pump	• Apache documents (procedures, work orders)	F8	86-89
14	Damage to plant	• Site visit by investigators • Witness statements	F1, F14, F19, F21, F26, F32, F33	1-4, 6, 38, 40-42, 63, 68, 69, 71, 72, 75, 114
15	Functioning of pipelines ESD equipment (ESD valves)	• Apache control room data • SDV test results • Witness statements	F24	1-4, 38, 40-42, 51, 62, 63, 59, 68, 69, 71, 72, 75, 81-83, 114, 226
16	Incident response on Varanus Island: • Personnel muster and evacuation • Shutting down/staring up plant (including actions near the incident site and the mainland compressor station CS1) • Incident assessment and monitoring • Plant shut down and blow down	• Apache individual personnel incident response records • Apache control and radio room data • Helicopter logs • Apache documentation including: - mainland CS1 P&IDs - storage tanks P&IDs - P&IDs for fire fighting and detection systems • Information from DGNB and GGT pipeline operators • Witness statements	F25, F26, F28, F29, F30, F31	1-4, 38, 40-42, 45, 53, 55, 56, 62-64, 65, 68, 69, 71, 72, 75, 92, 93, 113, 114, 116, 241-244

No.	Area covered	Information source	Report finding or section (Ref. No.)	Table 2 Information Log (Item. No.)
17	Applicable legislation - Pipeline Licenses, SC & PMP and requirements	• PPA 69, P(SL)A 82 • PL12, TPL8, • PMP • Varanus Hub Safety Case	Sect 9.2	
18	12” sales gas pipeline design and data: • design and fabrication specifications and data, • installation records • site (NNE beach geology).	• Apache documentation/ records (including drawings and reports) • PL12, TPL8 • PMP • DoIR records • Codes and standards	F17, F22, F44	84, 85, 185, 237-240
19	Anti- corrosion coating and CP for 12” sales gas line.	• Apache documentation • Codes and Standards • PMP • PL12, TPL8	F17, F22, F43, F45	20-25, 41, 154, 163, 164, 182, 245, 246, 248
20	Regulatory approvals required/obtained by Apache as stipulated in PLs (PL12 & TPL8), e.g. for CP design, intervals of inspections, corrective actions (repairs)?	• DoIR records/files	11.9	
21	Pipeline inspection requirements (legislative, codes and standards, good industry practice	• Relevant Australian and DNV standards • PL12, TPL8 • Pipeline corrosion expert report	Sect 9.2 & 11.9	247, 248, 258
22	Apache pipeline Inspection Maintenance and Monitoring Regime (IMMR)- past and current	• Apache IMMR policies, manuals and procedures • Apache/contractor assessment reports of the IMMR • Witness statements	F38-F42	9-37, 41, 63, 94-112, 122-194, 210-230, 232-235, 247, 248, 258
23	Structure of Apache Pipeline Inspection Maintenance and Monitoring Department/ Section, past and present, including number of personnel, positions, responsibilities, reporting lines.	• Apache documents • Witness statements	Sect 11.9.1, F36.	247, 254, 255

No.	Area covered	Information source	Report finding or section (Ref. No.)	Table 2 Information Log (Item. No.)
24	Resources allocated by Apache over time to pipeline IMMR.	• Apache documents • Witness statements	F36	41, 63, 189-192, 247, 254, 255
25	Use by Apache of contractors and independent specialists.	• Apache documents • Contractor pipeline condition and IMMR assessment reports • Witness statements	F37	28, 30, 31, 35, 37, 95-112, 122-152, 155-157, 159-176, 177-179, 180, 195, 196, 197, 210-216, 218-226, 247
26	Records of inspection, surveys and maintenance (repairs) carried out on pipelines crossing NNE beach, in particular, on 12" sales gas line.	• Apache pipeline inspection and survey reports • Apache/contractor pipeline assessment reports	F38-F41	17, 25, 171, 175, 176, 188
27	Pipelines failure mode	• Viewing by investigators of ruptured pipes (on site) , and pipe samples at PearlStreet laboratories • Non-destructive and destructive test results • Pipeline corrosion expert report • Metallurgist report	F17, F23, F33, F34, F35	259
28	Incident causes	All available information relevant to this incident	Sect. 12	
29	Possible breaches of legislation	• PPA69	Sect. 9.2, 13	

Table 2 - Information Log

Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
1	5/06/08	Statement - Witness	Gavin Smith (WA)						
2	5/06/08	Statement - Witness	Justin Morck (WA)						
3	5/06/08	Statement - Witness	Wayne Fletcher (WA)						
4	5/06/08	Statement - Witness	Wayne Simcock (WA)						
5	6/06/08	Drawing	VI Overview LM-00-DG-002	LM-00-DG-002	A				Feb 2006
6	6/06/08	Statement - Witness	Christopher Jackson (WA) - handwritten						
7	6/06/08	Operator Document	Cold Work Permit Package 03-06-2008				-		3/06/2008
8	6/06/08	Operator Document	Hot Work Permit Package 03-06-2008				-		3/06/2008
9	6/06/08	Operator Report	Onshore pipeline inspection - 8" Harriet Oil 2007	- img-6031721-0001					9/10/2007
10	6/06/08	Operator Report	Onshore pipeline inspection - 6" Harriet Gas Line 2007	- img-6031722-0001					7/10/2007
11	6/06/08	Operator Report	Onshore pipeline inspection - 12" Campbell Sinbad gas line 2007	- img-6031723-0001					3/09/2007
12	6/06/08	Operator Report	Onshore pipeline inspection - 12" Sales Gas Line 2007	- img-6031724-0001					7/08/2007
13	6/06/08	Operator Report	Onshore pipeline inspection - 16" Sales Gas Line 2007	- img-6031725-0001					11/10/2007
14	6/06/08	Operator Report	Onshore pipeline inspection - 30" Crude Export Line 2007	- img-6031726-0001					9/08/2002
15	6/06/08	Operator Report	Onshore pipeline inspection - extracts from AEL onshore inspection manual 2007	- img-6031727-0001					no date
16	6/06/08	Operator Report	5 Year Integrity Report - Sales Gas Lines - SP-14-RL-067 - Rev 0	SP-14-RL-067	0				30/05/2007
17	6/06/08	Operator Report	VI Ultra shallow water inspection - 17-05-2005	RE-AEL916-01	2				17/05/2005
18	6/06/08	Operator Report	Free Span Review - 12" - 22-12-2004 - SP-14-RL-004[1]	SP-14-RL-044	0	Ionik			22/12/2004
19	6/06/08	Operator Report	Free Span Assessment JPK - 12 Lvl1 - November 2004 - SP-14-RL-052[1]	SP-14-RL-052[1]		Ionik	07-0045-11-7-001	0	1/11/2004
20	6/06/08	Operator Report	CP Survey Summary 2000-2006			Auscor	L146002	A	
21	6/06/08	Operator Report	CP Survey - Sales Gas Pipeline - July 2003			Auscor	R1046001	A	29/07/2003
22	6/06/08	Operator Report	CP Survey - Sales Gas Pipeline - June 2002			Auscor	R1004001	A	June 2002
23	6/06/08	Operator Report	CP Survey - 12"/16" Sales Gas Pipeline Onshore section - July/Oct 2006 - Auscor			Auscor	R137101A	A	5/12/2006
24	6/06/08	Operator Report	CP Survey - Sales Gas Pipeline Mainland - 05-12-2006			Auscor	R137101A	A	5/12/2006
25	6/06/08	Operator Report	CP Survey - VI Onshore pipeline - August 2004 - OP-14-RU-003	OP-14-RU-003		Auscor	R115201A	A	16/02/2005
26	6/06/08	Operator Report	Free Span Assessment JPK - April 2005 - SP-14-RL-053[1]	SP-14-RL-053[1]		Ionik	07-0045-11-7-002	A	1/04/2005

Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
27	6/06/08	Operator Report	Post Cyclone Survey -29-05-2006 - SS-00-RU-038[1] - FUGRO	SS-00-RU-038[1]		Fugro	P0470	0	29/05/2006
28	6/06/08	Operator Report	Gap Analysis ModuSpec - 10-04-2007 - SP-14-RG-040			ModuSpec	PAU0060.1B	1.02	10/04/2007
29	6/06/08	Operator Report	Int Pig Review Iicorr CA 2003 - 235 - SP-14-RU-010			Iicorr	5231/RT3224	1	28/11/2003
30	6/06/08	Operator Report	Annual Environmental Report - Pages from - 03-10-2006						3/06/2008
31	6/06/08	Operator Report	Pipeline Risk Assessments ModuSpec - 10-04-2007 - SP-14-RG-039			ModuSpec	PAU0060.1	2	10/04/2007
32	6/06/08	Operator Report	Post Cyclone ROV Survey AEL - 24-04-2006 - SS-00-RU-037[1]	SS-00-RU-037	1				24/04/2006
33	6/06/08	Operator Report	Review of AEL Pipelines - QCL 06-02-2004				QCL 5226/2942	1	6/02/2004
34	6/06/08	Operator Report	Shallow Water ROV Survey - 06-05-2004 - SS-00-RU-027	REL AEL910-0401	1.0				6/05/2004
35	6/06/08	Operator Report	Free Span Assessment JPK - June 2000 - SP-14-RL-032[1]	SP-14-RL-032	B		01-0504-01-P-7-008	B	06/00
36	6/06/08	Operator Report	Subsoil pipe repair at KP 0-PB - 17-10-2004						17/10/2004
37	6/06/08	Operator Report	VI Ultra shallow water inspection - 17-05-2005 - RE-AEL916-01 Rev 2.0	RE-AEL916-01	2				17/05/2005
38	6/06/08	Statement - Witness	Brian Embelton (WA) draft						
39	6/06/08	Statement - Witness	Christopher Jackson - rock (WA)						
40	6/06/08	Statement - Witness	Mark Welten (WA)						
41	6/06/08	Statement - Witness	Peter Beckford (WA)						
42	6/06/08	Statement - Witness	Vince Simmington (WA)						
43	6/06/08	Operator Report	Accomomodation Status Report 03-06-2008				-		3/06/2008
44	6/06/08	Operator Report	Acommodation Status Report 04-06-2008				-		4/06/2008
45	6/06/08	Operator Document	Daily Helicopter Flight Movement 03-06-2008				-		3/06/2008
46	6/06/08	Operator Document	Offshore POB List 03-06-2008				-		3/06/2008
47	6/06/08	Operator Document	Panel Log 02-06-2008 Day				-		2/06/2008
48	6/06/08	Operator Document	Panel Log 02-06-2008 night				-		2/06/2008
49	6/06/08	Operator Document	Panel Log 03-06-2008 Day				-		3/06/2008
50	6/06/08	Operator Document	Panel Log 04-06-2008 Day				-		4/06/2008
51	6/06/08	Operator Document	Site Entry Register 04-06-2008				-		4/06/2008
52	6/06/08	Operator Document	SSU Consultant Forecast - VI - Chris Jackson 03-06-2008				-		3/06/2008

Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
53	6/06/08	Drawing	Varanus Island firewater system – Monitors and hydrants locations, - LT-10-DF-001	LT-10-DF-001	2				9/05/2008
54	6/06/08	Drawing	VI Facilities General Layout - LM-00-DG-001	LM-00-DG-001	D				14/03/2006
55	6/06/08	Drawing	VI Fire & Gas Detection - Set of 5	LG-05-DJ-575 LG-05-DJ-399 ES-40-DJ-748 ES-40-DJ-747 ES-DWG-60-F-0101	2 1 2 3 1				13/02/06 27/07/06 19/06/06 19/06/06
56	6/06/08	Drawing	VI Firewater Distribution - HJV Facilities - Piping and Instrument - LT-00-DX-005.02	LT-00-DX-005.02	3				9/05/2008
57	6/06/08	Drawing	VI Hazardous Area Identification - Set of 5	ES-40-DE-001.01 LG-05-DE-004 SM-10-DJ-163 LG-05-DJ-390 SM-10-DJ-162	52 7 4 1 3				02/11/06 19/11/02 09/08/06 09/08/06 04/06/02
58	6/06/08	Drawing	VI Pipeline Schematics - Set of 6	SP-14-DL-004 SP-14-DL-002 SP-14-DL-006 SP-14-DL-011 SP-20-DL-001 SP-21-DL-005	5 5 5 5 5 5				12/10/07 26/09/07 11/09/07 12/10/07 07/09/07 07/09/07
59	7/06/08	Operator Document	Key Codes Vigilant Fire Panel Signals				-		
60	7/06/08	Operator Document	ENTIS ENRAF Tank Inventory System 03-06-08				-		3/06/2008
61	7/06/08	Operator Document	SSU Consultant Forecast - VI - Kylie Hemmings 03-06-2008				-		3/06/2008
62	7/06/08	Statement - Witness	Prelim Statements by 3 AEL personnel						
63	7/06/08	Statement - Witness	Ross Paton (WA)						
64	7/06/08	Operator Report	Accommodation Status Report 03-06-2008 Muster Sheet 14:20-14:27				-		3/06/2008
65	7/06/08	Operator Document	Kylie Hemmings copy of notes Radio Room 03-06-2008				-		3/06/2008
66	9/06/08	Press Clip	The Australian - 07-06-2008						
67	10/06/08	Operator Report	Table - Contract Personnel Location on VI						
68	20/06/08	Statement - Witness	Tony Drake Brockman (WA)						20/06/2008
69	20/06/08	Statement - Witness	Ling Chang (James) Wong (WA)						20/06/2008
70	23/06/08	Statement - Witness	Unpacking Container A - Zbigniew Lambert						23/06/2008
71	4/07/08	Statement - Witness	Ivor Haora Davies						4/07/2008
72	4/07/08	Statement - Witness	Grant Thomas						4/07/2008
73	27/06/08	Statement - Witness	Unpacking Container B - Brian Richardson						27/06/2008

Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
74	30/06/08	Statement - Witness	Unpacking Container C - Brian Richardson						30/06/2008
75	9/07/08	Statement - Witness	Paul Solomon						9/07/2008
76	24/07/08	Operator Document	Process Plant Alarm Conditions - Pre & Post event - 3 documents						
77	24/07/08	Operator Document	Process Plant Fire & Gas Detection System Alarms - Pre & Post Event						17/06/2008
78	24/07/08	Operator Document	16" Sales Gas - Trend window of k12 Compressor Discharge						3/06/2008
79	24/07/08	Operator Document	12" Sales Gas - Trend Window of CM 11.301 & 11.302						3/06/2008
80	24/07/08	Operator Document	12" Sales Gas - Trend Window of ESGP Spill Overline						3/06/2008
81	24/07/08	Operator Document	12" Campbell Sinbad - Trend Window of Linda 12 & Bambra East 16						3/06/2008
82	24/07/08	Operator Document	8" Harriet Oil - Trend Window of Harriet Alpha 8 Export						3/06/2008
83	24/07/08	Operator Document	6" Harriet Gas - Trend Window Harriet Alpha 6 Gas						3/06/2008
84	24/07/08	Drawing	12" Sales Gas - Pipeline Schematic - SP-20-DL-001 Rev 5	SP-20-DL-001	5				7/09/2007
85	24/07/08	Drawing	16" Sales Gas - Pipeline Schematic - SP-21-DL-005 Rev 5	SP-21-DL-005	5				7/09/2007
86	24/07/08	Operator Document	30" Crude Oil - Appendix 2 Loading Line Oil Retrieval System - AE-91-IH-002 Rev 5	AE-91-IH-002	5				2005
87	24/07/08	Drawing	30" Crude Oil - Oil Retrieval Skid Orientation Plan - 00475-04071-0003 Rev 0			Crest Engineers	00475-04071-0003	0	
88	24/07/08	Operator Document	30" Crude Oil - Procedure for Draining & Preparing for Inspection						
89	24/07/08	Operator Document	30" Crude Oil - VI product Shipping Line Liquid Recovery Pump						
90	24/07/08	Operator Document	VI Lifting - 12 months Jun 07 - Apr 08	2008-07-08-Information Summary.xls					8/07/2008
91	24/07/08	Operator Document	ALERT Work Order - 03-06-2008						3/06/2008
92	24/07/08	Operator Document	Fire Control Philosophy VI - AE-10-ZF-001 Rev 1	AE-10-ZF-001	1				31/05/2001
93	24/07/08	Operator Document	Consolidated Emergency Response Plan - North West Shelf - AE-00-ZF-002 Rev 4	AE-00-ZF-002	4				10/08/2005
94	24/07/08	Operator Document	Emergency Pipeline Repair Plan - SP-14-RL-063 Rev 1	SP-14-RL-063	1				5/07/2007
95	24/07/08	Operator Document	CP Survey - Sales Gas Pipeline - Aug 2004 - Field Data Sheets			Auscor	AUS1153 Project: R115201A		15/08/2004
96	24/07/08	Operator Document	CP Survey - Sacrificial Anode Maintenance - Sales Gas Pipeline - Jun 2003			Auscor	AUS1032		17/06/2003
97	24/07/08	Operator Document	CP Survey - VI Offshore Pipelines - Onshore Section - Aug 2004 - OP-14-RU-003	OP-14-RU-003		Auscor	R115201A	A	16/02/2005
98	24/07/08	Operator Document	DCVG Survey - Sales Gas Pipeline - Sep 2004 - Field Data Sheets			Auscor	Project: AUS1154 Doc # F115403A		9/09/2004

Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
99	24/07/08	Operator Document	CP Survey - Sacrificial Anode Testing - Sales Gas Pipeline			Auscor	AUS1172		13/11/2004
100	24/07/08	Operator Document	CP Survey - Sales Gas Pipeline - Dec 2005 - Field Data Sheets			Auscor	Project: AUS1299 Doc # F129901A &		4/12/2005
101	24/07/08	Operator Document	CP Annual Survey - 12" & 16" Sales Gas - Onshore Section - Jul-Oct 2006			Auscor	R137101A	A	5/12/2006
102	24/07/08	Operator Document	Inspection & Corrosion Management Activities - Annual Summary Report - 2005 - AE-00	AE-00-RN-004	1				4/01/2006
103	24/07/08	Operator Document	Onshore Pipeline Inspection Manual - OP-14-MG-001 Rev 4						22/03/2006
104	24/07/08	Operator Document	Review of Recommendations - from 2004 - Pipeline Risk Assessments	SP-14-RG-039		ModuSpec	PAU0060.1		10/04/2007
105	24/07/08	Operator Document	Gap Analysis - Review of Apache Pipelines - 10-04-2007	SP-14-RG-040		ModuSpec	PAU0060.1B	Rel 02	10/04/2007
106	24/07/08	Operator Document	CP Survey - ROW Scouring Reinstatement - 02-11-2004			Auscor	AUS1158 L115804A		2/11/2004
107	24/07/08	Operator Document	CP Survey - 12" & 16" Sales Gas - Onshore CP Potential - 28-06-2000			Auscor	F9031A001A R9132K001A		28/06/2000
108	24/07/08	Operator Document	CP Survey - 12" & 16" Sales Gas - Onshore CP Potential - 04-03-2000			Auscor	F9001A02A R9133W001A		4/03/2000
109	24/07/08	Operator Document	DCVG Survey - 03-12-2000			Westcor	A9031		3/12/2000
110	24/07/08	Drawing	12" Sales Gas - Mainland to VI - Alignment - Set of 13	SP-00-DL-001 - SP-00-DL-013		Fugro			
111	24/07/08	Drawing	16" Sales Gas - Offshore Pipeline - Alignment - Set of 8						
112	24/07/08	Operator Document	Shallow Water Inspection Program - Results - 2003	RE-AEL910-0401	1.0				6/05/2004
113	24/07/08	Operator Document	Bristow - VH-BKK Tech Log - 03-06-2008			Bristow			3/06/2008
114	21/07/08	Statement - Witness	Zachary Bennett						21/07/2008
115	5/08/08	Operator Document	Responses to Queries from DoIR to GGT			GGT			4/08/2008
116	5/08/08	Operator Document	Bristow - VH-BKK Tech Log - 03-06-2008 Part B						
117	8/09/08	Statement- Witness	Discussion of Proposed Revised Sample Testing Protocol 05/09/2008						8/09/2008
118	7/08/08	Index	Information Requested and Provided from AEL Requests 2 and 3			AEL			7/08/2008
119	7/08/08	Operator Document	Standing Order - Fire Damaged Area Restricted Access	SO 030	0	AEL			3/06/2008
120	7/08/08	Operator Document	Tool Box Meeting Topic	Ross Elliott	0	AEL			13/06/2008
121	7/08/08	Operator Document	VI Safety Advisors Procedures as at June 2008			AEL			
122	7/08/08	Drawing	Repair of Joint 101 as Built Details			McDermott	8522-AB4	1	27/05/1992
123	7/08/08	Operator Document	HEL - Onshore sales Gas Line Pipeline Inspection General Visual Environmental Survey	1STEJSKAL					1/03/2008

Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
124	7/08/08	Operator Document	HEL - Onshore Sales Gas Pipeline Cathodic Protection Survey May 1993			Taywood Engineering Ltd	1303/93/6487/6068		1/05/1993
125	7/08/08	Operator Document	HEL - ROV Pipeline Inspection 12" Sales Gas Pipeline Onslow WA	B867/SS-14-RU-005		Fugro Survey	HY9561		28/09/1993
126	7/08/08	Operator Document	Memorandum - To: Neville Jones From: Iva Stejskal - SGL Pipeline Inspection 21 Oct 19	is14M.DOC					4/11/1993
127	7/08/08	Operator Document	HEL - 324mm SGL Pipeline Inspection - Summary Report August 1993	SP14UL.005					2/12/1993
128	7/08/08	Operator Document	HEL - 324mm SGL Pipeline Inspection - Detailed Report May 1993	OP-00-UL-001					15/12/1993
129	7/08/08	Operator Document	HEL - 324mm SGL Pipeline Inspection Report November 1992	SP-14-UL-006					17/12/1993
130	7/08/08	Operator Document	HEL - 324mm SGL 1993 Inspection Findings - Stability and Spanning Analysis			JP Kenny	01013360P3001		1/02/1994
131	7/08/08	Operator Document	HEL - Pipeline Embedment Survey Report 12" SGL & Infield Flow Line Volume 1			Racal	A2263		25/07/1994
132	7/08/08	Operator Document	HEL - Pipeline Embedment Survey Report 12" SGL & Infield Flow Line Volume 2			Racal	A2263		25/07/1994
133	7/08/08	Operator Document	RACAL & HEL Joint Report 12" SGL & Infield Flow Line Investigations	SP-29-RL-001		Racal	A2292		10/10/1994
134	7/08/08	Operator Document	Positioning Report for Tamboritha Consultants Post Cyclone Bobby ROV Survey	SP-KI-RC-019		Racal	A2368		21/03/1995
135	7/08/08	Operator Document	Offshore Installation Close Out Report SGL Pipeline Stabilisation Volume II	SP-14-RL-004					27/06/1995
136	7/08/08	Operator Document	Offshore Installation Close Out Report SGL Pipeline Stabilisation Volume II	SP-14-RL-004	02				7/06/1995
137	7/08/08	Operator Document	Offshore Installation Close Out Report SGL Pipeline Stabilisation Volume III	SP-14-RL-004	03				3/07/1995
138	7/08/08	Operator Document	AEL Annual Pipeline Inspection	SP-14-RL-024		Tamboritha Consultants	TCR9614.001		10/06/1996
139	7/08/08	Operator Document	AEL Sales Gas Pipeline Survey Report	OP-00-UL-002					7/01/1996
140	7/08/08	Operator Document	AEL 1996 Sales Gas Pipeline Geophysical Survey	SP-20-RL-007		Tamboritha Consultants	TCC9630.097		29/07/1996
141	7/08/08	Drawing	SGL Pipeline Inspection - KP 67.101			Tamboritha Consultants	TC9630DR.031		11/07/1996
142	7/08/08	Drawing	SGL Pipeline Inspection at KP 67.101			Tamboritha Consultants	TC9630DR.058		
143	7/08/08	Drawing	SGL Pipeline Inspection (Pipe Straightness)			Tamboritha Consultants	TC9630SK.022		29/08/1996
144	7/08/08	Drawing	SGL Bent Pipe Strengthening Clamp			Tamboritha Consultants	TCD9630-0001		
145	7/08/08	Operator Document	AEL - MV Amada Goodman Daily Operations Report			Tamboritha Consultants	TCR9630.002		1/11/1996
146	7/08/08	Operator Document	AEL 1996 SGL Pipeline Re-Stabilisation Program Interim Report	SP-14-RL-028		Tamboritha Consultants	TCR9630.003		1/11/1996
147	7/08/08	Operator Document	SGL Repairs Close Out Report	SP-20-RL-001					25/11/1996
148	7/08/08	Operator Document	SGL Insurance Claim Report	SP-20-RG-005		JP Kenny	01-0194-05-P-3-004		1/12/1996

Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
149	7/08/08	Operator Document	AEL 1995 Pipeline Stabilisation Maintenance	SP-14-RL-018		Tamboritha Consultants	TCR9520.001		13/02/1996
150	7/08/08	Operator Document	AEL 1996 SGL Pipeline Re-Stabilisation Program Vol 1	SP-20-RL-003.03	03	Tamboritha Consultants	TCR9630.002		24/03/1997
151	7/08/08	Operator Document	AEL 1996 SGL Pipeline Re-Stabilisation Program Vol 2	SP-20-RL-003.03	03	Tamboritha Consultants	TCR9630.002		24/03/1997
152	7/08/08	Operator Document	AEL 1996 SGL Pipeline Re-Stabilisation Program Vol 3	SP-20-RL-003.03		Tamboritha Consultants	TCR9630.002		1/11/1996
153	7/08/08	Operator Document	AEL SGL Survey Report 1997	OP-00-RU-001					5/12/1997
154	7/08/08	Operator Document	Onshore SGL Cathodic Protection Survey 1997	OP-00-RU-002					5/12/1997
155	7/08/08	Operator Document	AEL SGL Diving Survey July 1996	SP-20-RU-001/A		Tamboritha Consultants	TCR9634.001		26/07/1996
156	7/08/08	Operator Document	12 & 16" SGL Mainland Section AS2885 Risk Assessment 1998	SP-21-RF-004		Stratex Pty Ltd	050/07192		19/06/1998
157	7/08/08	Operator Document	12 & 16" SGL Offshore Section AS2885 Risk Assessment 1998	SP-21-RF-003		Stratex Pty Ltd	050/07192		11/08/1998
158	7/08/08	Operator Document	AEL 12" & 16" SGL Route Inspection	SP-14-RU-001					17/06/2000
159	7/08/08	Operator Document	AEL 12" & 16" SGL Onshore Cathodic Protection Potential Survey			Westcor Engineering	Apache/9031A		28/06/2000
160	7/08/08	Operator Document	AEL Shallow Water Pipelines Span Assessment	SP-14-RL-032		JP Kenny	01/0504/01/P/7/008		1/06/2000
161	7/08/08	Operator Document	Corrpro Companies Australia DCVG Survey 2000						3/12/2000
162	7/08/08	Operator Document	12" SGL Rock Anchor Failure Review 2001	SP-20-RG-009		JP Kenny	01/0504/02/P/7/002		1/09/2001
163	7/08/08	Operator Document	Onshore 12"/16" SGL Cathodic Protection Survey June 2002			Auscor Pty Ltd	R1004001A		1/06/2002
164	7/08/08	Operator Document	Onshore 12"/16" SGL Cathodic Protection Survey June 2003			Auscor Pty Ltd	R1046001A		1/06/2003
165	7/08/08	Operator Document	12" & 16" Sales, Wonnich and East Spar Pipelines Post Cylcone Monty Side Scan Sonar Inspection Survey			Fugro Survey	P0008		6/04/2004
166	7/08/08	Operator Document	2003 Shallow Water Inspection Program - Results			Netlink Inspection Services	RE-AEL910-0401		6/05/2004
167	7/08/08	Operator Document	2003 Shallow Water Inspection Program - Appendix A - Operations			Netlink Inspection Services	RE-AEL910-0401		6/05/2004
168	7/08/08	Operator Document	Letter from Auscor to AEL Re: SGL Cathodic Protection - Sacrificial Anodes 8 Nov 2004			Auscor Pty Ltd	L117201A		8/11/2004
169	7/08/08	Operator Document	2004 Level 1 Freespan Assessment			Ionik Consulting	07/0045/11/7/001		1/11/2004
170	7/08/08	Operator Document	VI Ultra Shallow Water and Onshore Pipeline Inspection Oct 2004			Netlink Inspection Services	Re-AEL-916-01	2	15/10/2004
171	7/08/08	Operator Document	VI Offshore pipework Monitoring 2006			Auscor Pty Ltd			18/06/2006

Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
172	7/08/08	Operator Document	12"/16" SGL Onshore Section DCVG Coating Survey August 2007			Auscor Pty Ltd	R151801	B	1/03/2008
173	7/08/08	Operator Document	12"/16" SGL Onshore Section Cathodic Protection Annual Survey August 2007			Auscor Pty Ltd	R151701	A	1/03/2008
174	7/08/08	Operator Document	SGL 5 Year Integrity Review 2007	SP-14-RL-067					30/05/2007
175	7/08/08	Operator Document	2007 Onshore Pipeline Inspection Workbook	OP-14-MG-001					22/03/2006
176	7/08/08	Operator Document	VI Offshore Pipework Monitoring MCC Building 2008			Auscor Pty Ltd			3/05/2008
177	7/08/08	Operator Document	Underwater Inspection Manual 2004	AE-00-MG-005	3				13/09/2004
178	7/08/08	Operator Document	Corrosion Management System - Coating Inspection Procedure 2003	AE-91-IG-0058	3				15/07/2003
179	7/08/08	Operator Document	Guidelines - Analysis of Inspection Results and Remedial Actions			QCL International	5106/1983	1	31/08/1983
180	7/08/08	Operator Document	Anomoly Report, Pipeline General Inspection, Daily Calibration Log, Daily Report Fax Message, Film Log, Operation Log, Photograph Index, Onshore Pipeline Inspection Manual	OP-00-DX-101.02					24/05/1999
181	7/08/08	Operator Document	Onshore SGL (PL/17) Pipeline Inspections Manual	OP-00-SL-001					3/05/1993
182	7/08/08	Operator Document	Harriet Gas Project Specification No. OP-00-SX-004 Onshore Cathodic Protection	OP-00SX004					21/01/2004
183	7/08/08	Operator Document	Onshore Pipeline Inspection Manual 2003	OP-14-MG-001		QCL International	5218/0734		1/01/2003
184	7/08/08	Operator Document	Onshore Pipeline Inspection Manual 1999	OP-14-MG-001					22/07/1999
185	7/08/08	Operator Document	Harriet Gas Project Specification No. SP-00-GX-003 Pipeline Design Basis	SP-00-SX-003	A				22/04/1991
186	7/08/08	Operator Document	Underwater Pipeline Inspection Manual 1999	SP-14-ML-001	2	QCL International			1/03/1999
187	7/08/08	Operator Document	Underwater Inspection Manual 2003	AE-00-MG-005	1	QCL International			3/06/2003
188	7/08/08	Operator Document	VI Offshore Pipework Monitoring 2007			Auscor Pty Ltd			1/08/2007
189	7/08/08	Operator Document	Position Description - Chief Facilities Engineer						
190	7/08/08	Operator Document	Position Description - Operations Manager						
191	7/08/08	Operator Document	Position Description - Field Superintendent						
192	7/08/08	Operator Document	Integrity Management Personnel and Competencies Description	AE-91-IO-001					24/01/2008
193	7/08/08	Operator Document	Underwater Inspection Manual	AE-00-MG-005					5/08/2005
194	7/08/08	Operator Document	Onshore Pipeline Inspection Manual	OP-14-MG-001					22/03/2006
195	7/08/08	Operator Document	Procedure for Mobilising Contractors to Site	AE-00-ZF-012	3				5/06/2006

Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
196	7/08/08	Operator Document	Assurance of Contractor Safety Management	AE-00-ZF-037					30/11/2007
197	7/08/08	Operator Document	Procedure for Preparation and Approval of Contracts for Services	AE-91-IQ-030	C				14/06/2000
198	7/08/08	Meter Reading	Meter Reading - M2 Meter 03/06/2008 00:00 - 08:00 Raw Data						3/06/2008
199	7/08/08	Meter Reading	Meter Reading - M2 Meter 03/06/2008 08:00 - 16:00 Raw Data						3/06/2008
200	7/08/08	Meter Reading	Meter Reading - M2 Meter 03/06/2008 16:00 - 24:00 Raw Data						3/06/2008
201	7/08/08	Meter Reading	Meter Reading - M7 Meter 03/06/2008 00:00 - 08:00 Raw Data						3/06/2008
202	7/08/08	Meter Reading	Meter Reading - M7 Meter 03/06/2008 08:00 - 16:00 Raw Data						3/06/2008
203	7/08/08	Meter Reading	Meter Reading - M7 Meter 03/06/2008 16:00 - 24:00 Raw Data						3/06/2008
204	7/08/08	Meter Reading	Meter Reading - M3 Meter 03/06/2008 00:00 - 08:00 Raw Data						3/06/2008
205	7/08/08	Meter Reading	Meter Reading - M3 Meter 03/06/2008 08:00 - 16:00 Raw Data						3/06/2008
206	7/08/08	Meter Reading	Meter Reading - M3 Meter 03/06/2008 16:00 - 24:00 Raw Data						3/06/2008
207	7/08/08	Drawing	Lowendal Island Facilities Crude Oil Storage Tanks Piping & Instrument Diagram	LT-00-DX-001	14				
208	7/08/08	Drawing	Lowendal Island Facilities Shipping Transfer Pumps Piping & Instrument Diagram	LT-00-DX-002	14				
209	7/08/08	Drawing	Lowendal Island Facilities Pig Receiver L-101(L) & Load Out Valve MVS-G102 Piping & Instrument Diagram	LT-00-DX-012	8				
210	7/08/08	Operator Document	Lloyd's Register - AEL North West Shelf Operations Validation Plan May 2006						25/05/2006
211	7/08/08	Operator Document	Lloyd's Register - AEL Integrity Audit Report 12-19 May 2006						31/05/2006
212	7/08/08	Operator Document	Lloyd's Register - AEL North West Shelf Operations Validation Plan August 2006						8/08/2006
213	7/08/08	Operator Document	Lloyd's Register - AEL Process Integrity Review 12-14 June 2006						30/06/2006
214	7/08/08	Operator Document	Lloyd's Register - AEL Process Integrity Review 3-7 August 2006						21/08/2006
215	7/08/08	Operator Document	Lloyd's Register - AEL Process Integrity Review 28 September - 2 October 2006						20/12/2006
216	7/08/08	Operator Document	Lloyd's Register - AEL PL12 Validation Summary report May 2006 - April 2007	AE-14-RL-003	A				1/05/2007
217	7/08/08	Operator Document	Pigging of Simpson Pipeline and Removal of Pig						24/09/2007
218	7/08/08	Operator Document	AEL - Review of Apache Energy Pipelines	SP-14-RF-003.01	3	QCL International			xx/xx/2003
219	7/08/08	Operator Document	Operational Pipeline Management Plan Volume 1	SP-90-RL-002.1.1		Ionik Consulting			1/03/2008
220	7/08/08	Operator Document	Operational Pipeline Management Plan Reference Document	SP-90-RL-002.1.2		Ionik Consulting			1/03/2008

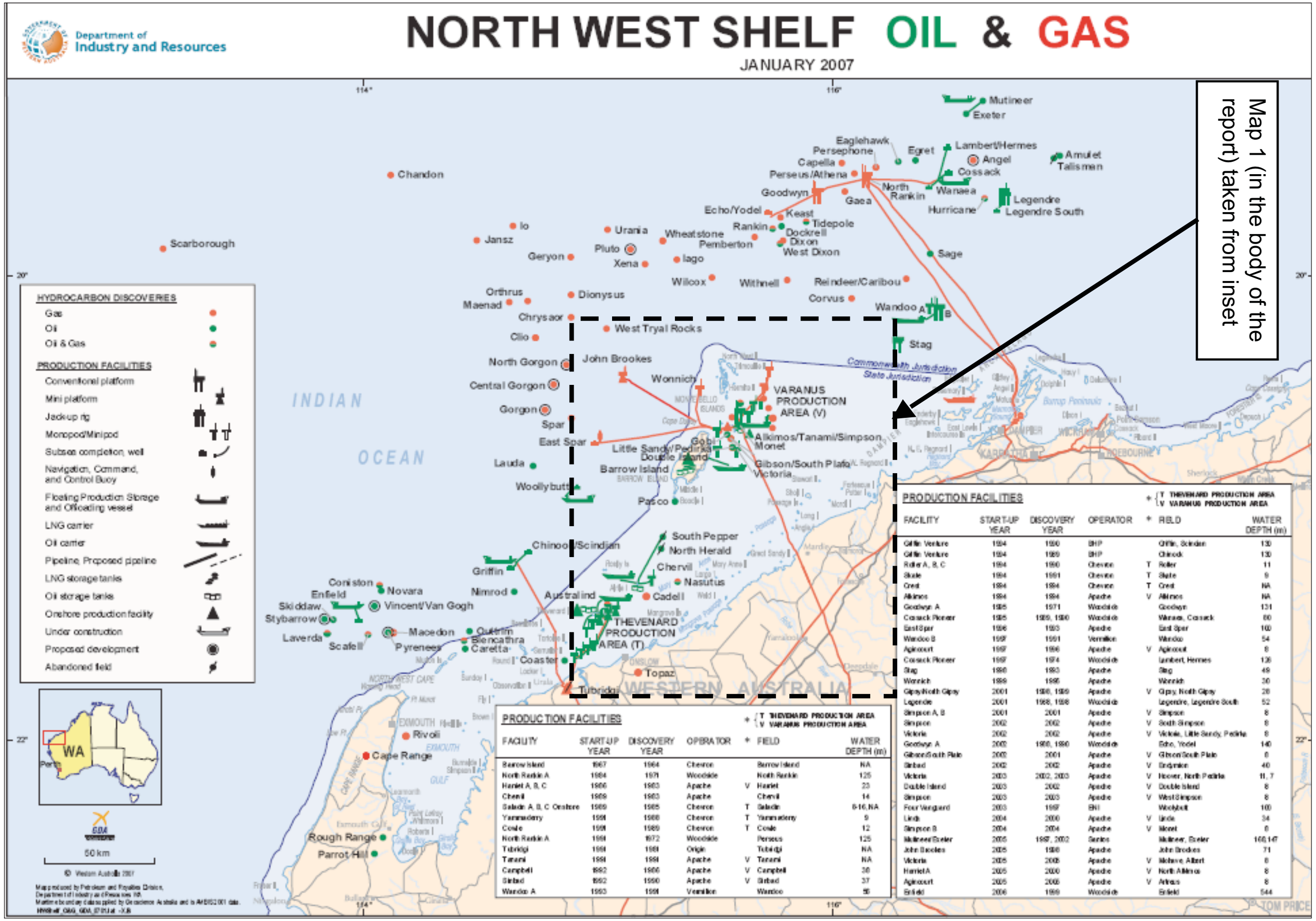
Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
221	7/08/08	Operator Document	Operational Pipeline Management Plan Facilities Descriptions	SP-90-RL-002.2.1		Ionik Consulting			1/03/2008
222	7/08/08	Operator Document	Operational Pipeline Management Plan Sales 12" Gas Line - FD	SP-90-RL-002.2.6		Ionik Consulting			1/03/2008
223	7/08/08	Operator Document	Operational Pipeline Management Plan Formal Safety Assessment & Risk Summary	SP-90-RL-002.4.1		Ionik Consulting			1/03/2008
224	7/08/08	Operator Document	Operational Pipeline Management Plan Sales 12" Gas Line - FSA	SP-90-RL-002.4.26		Ionik Consulting			1/03/2008
225	7/08/08	Operator Document	Operational Pipeline Management Plan Master Table of Contents	SP-90-RL-002		Ionik Consulting			1/03/2008
226	1/09/08	Operator Document	Inspection report of AEL 16" 1500CL SDV	ENG-SC6-J-A-3546-3		Score (Pacific) Pty Ltd	ER 9089		12/08/2008
227	7/08/08	Operator Document	Corrosion Management System - Coating Inspection Procedure	AE-91-IG-005	4				27/09/2007
228	7/08/08	Operator Document	Analysis of Inspection Results and Remedial Actions	AE-91-MU-001	2				22/03/2006
229	7/08/08	Operator Document	Pipeline Corrosion and Integrity Management Strategy	AE-00-MN-001	2				24/02/2000
230	7/08/08	Operator Document	Inspection Manager Enterprise Asset Information Update, Revision & Addition Procedure	AE-91-IQ-203	2				24/08/2005
231	7/08/08	Operator Document	VI POB List for 22 May 2008						
232	7/08/08	Operator Document	United Group Resource Job Pre-Start Meeting Notes						22/05/2008
233	7/08/08	Operator Document	Clough Mars Pre-Start Meeting Minutes						22/05/2008
234	7/08/08	Operator Document	Wilson's Pipe Fabrication Job Pre-Start Meeting Notes						22/05/2008
235	7/08/08	Operator Document	AEL Toolbox Meeting Minutes						22/05/2008
236	21/08/08	Index	Information Requested and Provided from AEL Requests 2 and 3						
237	21/08/08	Drawing	Varanus Island Facilities - Piping General Arrangement - Launcher & Receiver Trench LG-00-DX-028			Kirk	LG-00-DX-028		
238	21/08/08	Drawing	Varanus Island Facilities - Profile of Piping - Launcher & Receiver Trench LG-00-DX-029				LG-00-DX-029		
239	21/08/08	Operator Document	Installation of Subsea Gas Pipelines - For Gas Gathering Scheme - Marine Monitoring Programme			LeProvost Environmental Consultants	Report No R375		20/12/1991
240	21/08/08	Operator Document	Harriet Gas Project - Pipelines - Project Data Book - Materials Traceability and Certificati	SP-00-TL-004		Bredero Price	MP 8902		
241	21/08/08	Drawing	AEL Metering Station Capacity - Expansion & GGT Tie Ins			PCT Engineers	738-DPI-003	6	2/06/1995
242	21/08/08	Drawing	CSI Metering Station Facilities - Meter Run 4 & 5 Piping & Instrument Diagram			PCT Engineers	GP-09-DX-031	6	2/09/1999
243	21/08/08	Drawing	VI Facilities Piping & Instrument Diagram PIG Receivers R-100 & R-200 LG-00-DX-002	LG-00-DX-002					
244	21/08/08	Drawing	VI Facilities Piping & Instrument Diagram PIG Launcher R-300 LG-00-DX-012	LG-00-DX-012					

Item	Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
245	21/08/08	Photograph	AEL Photo showing CP System Isolation Flanges for 12" SGP and 12" Campbell/Sinbad Pipeline	20080825185122148					
246	1/09/08	Photograph	AEL Photo marked up to show CP System Isolation Flanges for 12" SGP and 12" Campbell/Sinbad Pipeline	20080825185122148					
247	8/09/08	Personnel Statement	Corporate Response of Apache Northwest Pty Ltd to Questions Posed by DoIR for Production Manager, Ivor Alexander						8/09/2008
248	8/09/08	Personnel Statement	Australian Standard 2885-1987 Pipelines - Gas and Liquid Petroleum	AMDT 1/1990-08-C					12/10/1987
249	8/09/08	Personnel Statement	Lloyd's Register Integrity Audit Report 12 to 19 May 2006	APAC.002.2183					31/05/2006
250	8/09/08	Personnel Statement	Lloyd's Register Process Integrity Review 12 to 14 June 2006	APAC.002.2215					30/06/2006
251	8/09/08	Personnel Statement	Lloyd's RegisterNorth West Shelf Operations Validation Plan						8/08/2006
252	8/09/08	Personnel Statement	Lloyd's Register PL12 Validation Summary Report May 2006 - April 2007						10/05/2007
253	8/09/08	Personnel Statement	Lloyd's Register Process Integrity Review 3 to 7 August 2006	APAC.002.2242					21/08/2006
254	8/09/08	Personnel Statement	Operations Organisational Structure Charts						1/02/2008
255	8/09/08	Personnel Statement	AEL Integrity Management Personnel and Competencies Description	AE-91-IO-001					24/01/2008
256	8/09/08	Personnel Statement	NOPSA Additional Requirements for the PSMP Worksheet						25/10??
257	8/09/08	Personnel Statement	DoIR Letter - Acceptance of Global PMP			DoIR	H0034/08/04		28/03/2008
258	8/09/08	Personnel Statement	Australian Standard 2885.3-2001 Pipelines - Gas and Liquid Petroleum Part 3: Operations and Maintenance			Standards Australia	AS 2885.3-2001		
259	18/08/08	Reports	CD containing Reports 8A5/MET1 to 8A//MET15 on findings of Non-Destructive Testing			PearlStreet Laboratories			

Document Log - Documentary Evidence - VI Incident 03-06-2008.xls

Date Rec'd	Document Class	Document Title	AEL REF	REV	Ext Comp	External Company Ref	REV	Doc Date
21/08/08	Index	Information Requested and Provided from AEL Requests 2 and 3						
21/08/08	Drawing	Varanus Island Facilities - Piping General Arrangement - Launcher & Receiver Trench LG-00-DX-028			Kirk	LG-00-DX-028		
21/08/08	Drawing	Varanus Island Facilities - Profile of Piping - Launcher & Receiver Trench LG-00-DX-029				LG-00-DX-029		
21/08/08	Operator Document	Installation of Subsea Gas Pipelines - For Gas Gathering Scheme - Marine Monitoring Programme			LeProvost Environmental Consultants	Report No R375		20/12/1991
21/08/08	Operator Document	Harriet Gas Project - Pipelines - Project Data Book - Materials Traceability and Certification	SP-00-TL-004		Bredero Price	MP 8902		
21/08/08	Drawing	AEL Metering Station Capacity - Expansion & GGT Tie Ins			PCT Engineers	738-DPI-003	6	2/06/1995
21/08/08	Drawing	CSI Metering Station Facilities - Meter Run 4 & 5 Piping & Instrument Diagram			PCT Engineers	GP-09-DX-031	6	2/09/1999
15/09/08	Operator Document	LTS, Sinbad, Campbell and Compression Station 1 Corrosion Risk Assessment and Inspection Scheme	HE-00-MN-003		QCL International	5015/1013	1	1/09/1998
15/09/08	Operator Document	1999 Shallow Water - Underwater Inspection Workbook Volume II - Pipelines			QCL International	5053/1739	0	1/12/1999
15/09/08	Operator Document	1999 Shallow Water Inspection Report Phase 1 & 2			Tamboritha Consultants	9-TCR9954[1].001		14/08/2000
15/09/08	Operator Document	Assessment of the 1999 Shallow Water ROV Inspection (Part 1)	SS-00-RU-006		QCL International	5110/2035	1	4/04/2001
15/09/08	Operator Document	Shallow Water ROV Inspection Program - 2003 Work Procedure Manual			Tamboritha Consultants	TCCON0317.002	0	1/12/2003
15/09/08	Operator Document	Auscor Pty Ltd VI Offshore Pipelines - Onshore Section Cathodic Protection Survey August 2004			Auscor Pty Ltd	R115201A	A	16/02/2005
15/09/08	Operator Document	2003 Shallow Water Underwater Inspection ROV Workbook	SS-00-RU-023		QCL International	5252/R3134	1	11/04/2003
15/09/08	Operator Document	Quality Control of Survey Data Acquisition - Pipeline Investigations for AEL - Sales Pipeline, Wonnich Pipeline, East Spar Pipeline March 2004			ECL	1409		13/03/2004
15/09/08	Operator Document	2005 Annual Summary Report of Inspection and Corrosion Management Activities	AE-00-RN-004					9/05/2005
15/09/08	Operator Document	Statutory Inspection Manual	HE-00MF-001					30/11/1992
24/09/08	Operator Document	2006 Post Cyclone ROV Survey - Work Procedure Manual Offshore Working Copy	SS-00-RU-036					6/04/2006

North West Shelf Oil & Gas Facilities



PRODUCTION FACILITIES

* { T THEVENARD PRODUCTION AREA; V VARANUS PRODUCTION AREA

FACILITY	START-UP YEAR	DISCOVERY YEAR	OPERATOR	*	FIELD	WATER DEPTH (m)
Barrow Island	1967	1964	Chevron		Barrow Island	NA
North Rankin A	1984	1971	Woodside		North Rankin	125
Harriet A, B, C	1986	1983	Apache	V	Harriet	23
Chervil	1989	1983	Apache		Chervil	14
Saladin A, B, C Onshore	1989	1985	Chevron	T	Saladin	8-16, NA
Yammaderry	1991	1988	Chevron	T	Yammaderry	9
Cowle	1991	1989	Chevron	T	Cowle	12
North Rankin A	1991	1972	Woodside		Perseus	125
Tubridgi	1991	1981	Origin		Tubridgi	NA
Tanami	1991	1991	Apache	V	Tanami	NA
Campbell	1992	1986	Apache	V	Campbell	38
Sinbad	1992	1990	Apache	V	Sinbad	37
Wandoo A	1993	1991	Vermilion		Wandoo	56

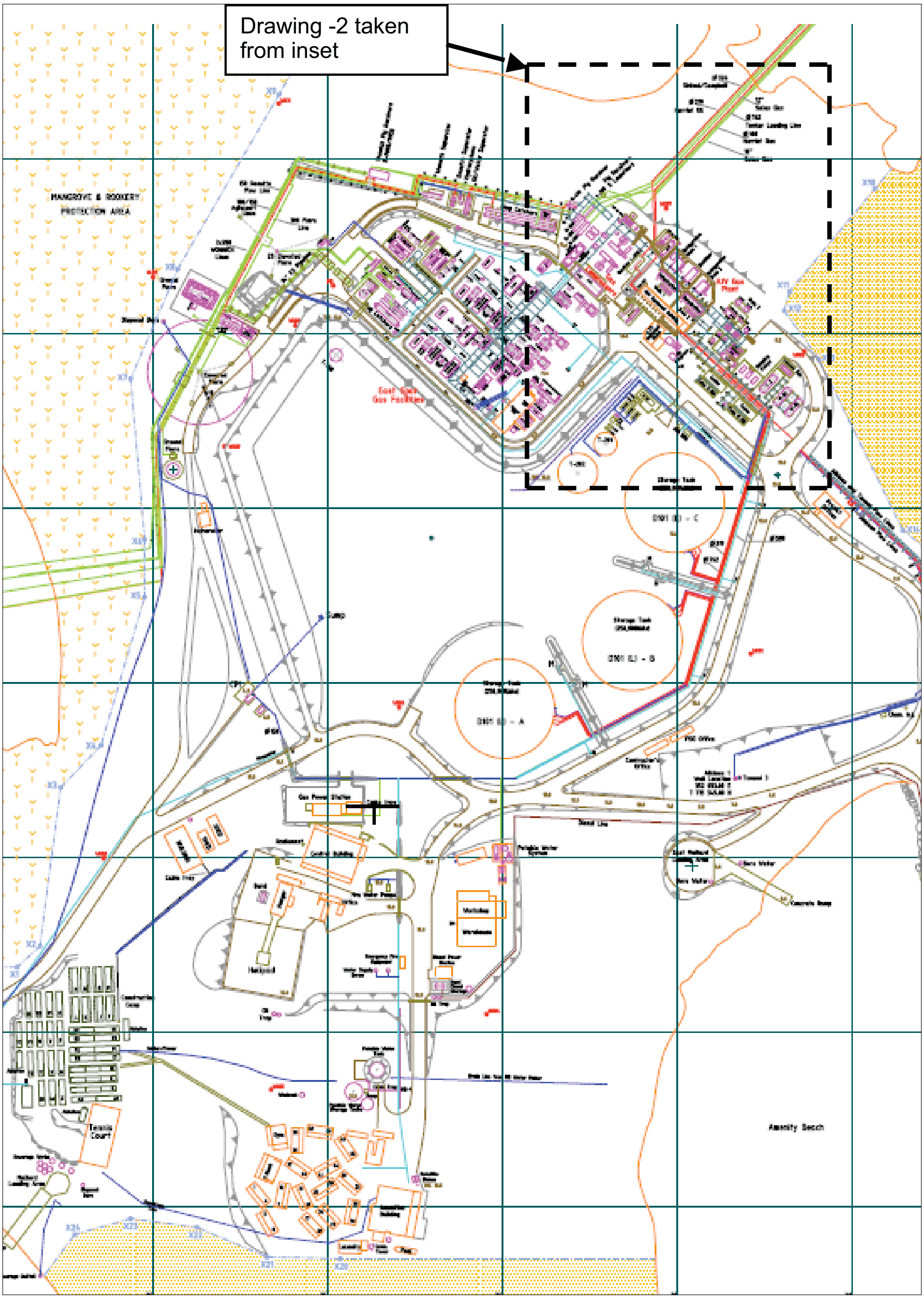
PRODUCTION FACILITIES

* { T THEVENARD PRODUCTION AREA; V VARANUS PRODUCTION AREA

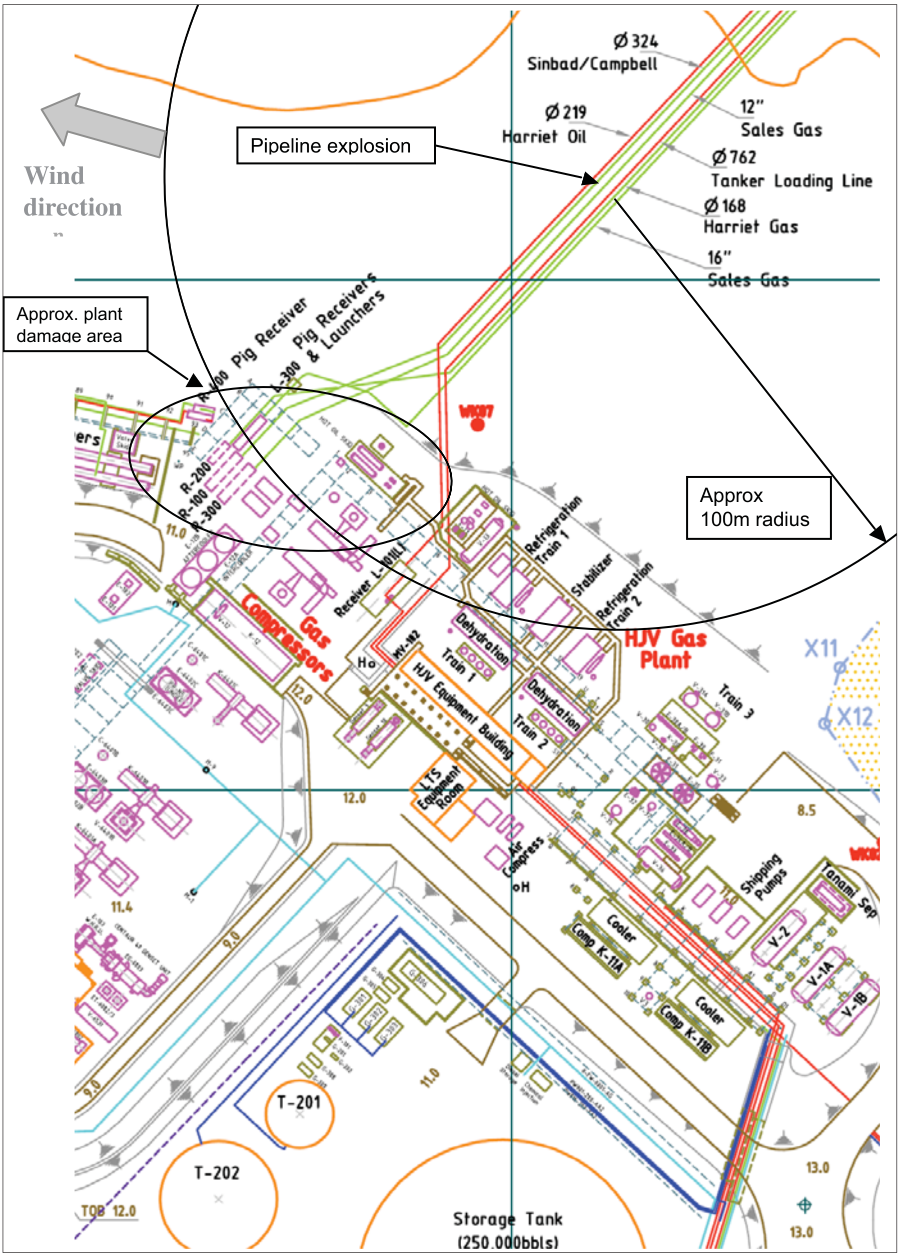
FACILITY	START-UP YEAR	DISCOVERY YEAR	OPERATOR	*	FIELD	WATER DEPTH (m)
Griffin Venture	1994	1990	BHP		Griffin, Scindian	130
Griffin Venture	1994	1989	BHP		Chinook	130
Roller A, B, C	1994	1990	Chevron	T	Roller	11
Skate	1994	1991	Chevron	T	Skate	9
Crest	1994	1994	Chevron	T	Crest	NA
Alkimos	1994	1994	Apache	V	Alkimos	NA
Goodwyn A	1995	1971	Woodside		Goodwyn	131
Cossack Pioneer	1995	1989, 1990	Woodside		Wanaea, Cossack	80
East Spar	1996	1993	Apache		East Spar	100
Wandoo B	1997	1991	Vermilion		Wandoo	54
Agincourt	1997	1996	Apache	V	Agincourt	8
Cossack Pioneer	1997	1974	Woodside		Lambert, Hermes	126
Stag	1998	1993	Apache		Stag	49
Wonnich	1999	1995	Apache		Wonnich	30
Gipsy/North Gipsy	2001	1998, 1999	Apache	V	Gipsy, North Gipsy	28
Legendre	2001	1968, 1998	Woodside		Legendre, Legendre South	52
Simpson A, B	2001	2001	Apache	V	Simpson	8
Simpson	2002	2002	Apache	V	South Simpson	8
Victoria	2002	2002	Apache	V	Victoria, Little Sandy, Pedirka	8
Goodwyn A	2002	1980, 1990	Woodside		Echo, Yodel	140
Gibson/South Plato	2002	2001	Apache	V	Gibson/South Plato	8
Sinbad	2002	2002	Apache	V	Endymion	40
Victoria	2003	2002, 2003	Apache	V	Hoover, North Pedirka	11, 7
Double Island	2003	2002	Apache	V	Double Island	8
Simpson	2003	2003	Apache	V	West Simpson	8
Four Vanguard	2003	1997	ENI		Woollybutt	100
Linda	2004	2000	Apache	V	Linda	34
Simpson B	2004	2004	Apache	V	Monet	8
Mutineer/Exeter	2005	1997, 2002	Santos		Mutineer, Exeter	160,147
John Brookes	2005	1998	Apache		John Brookes	71
Victoria	2005	2005	Apache	V	Mohave, Albert	8
Harriet A	2005	2000	Apache	V	North Alkimos	8
Agincourt	2005	2005	Apache	V	Artreus	8
Enfield	2006	1999	Woodside		Enfield	544

Attachment 4

Drawing 1 – Apache Varanus Island production facilities



Drawing 2 – Location of explosion on beach



Attachment 5

Photo 1 – Varanus Island

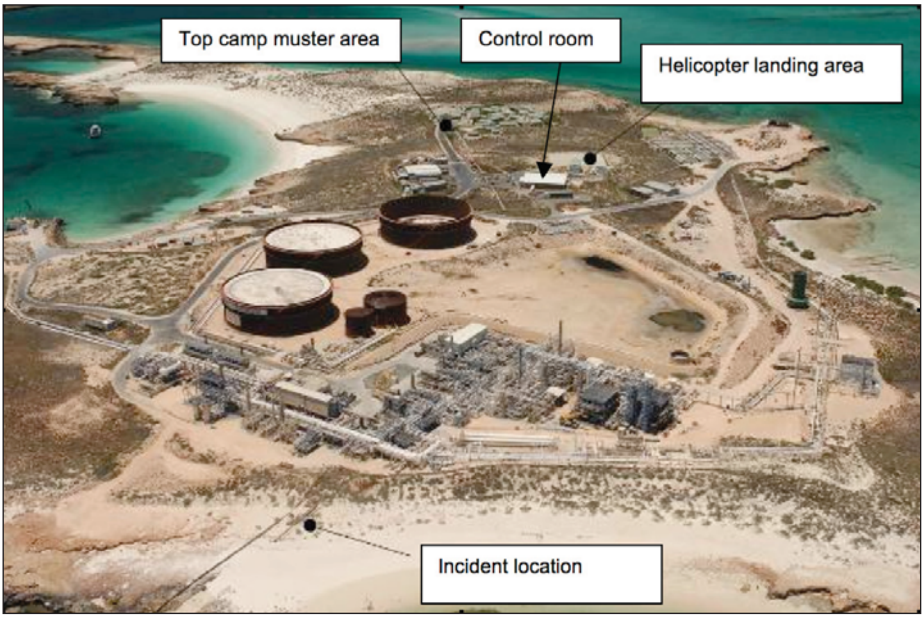


Photo 2 - Varanus Island fire and explosion incident, view from helicopter

Photo 3 – Varanus Island NNE beach, incident site

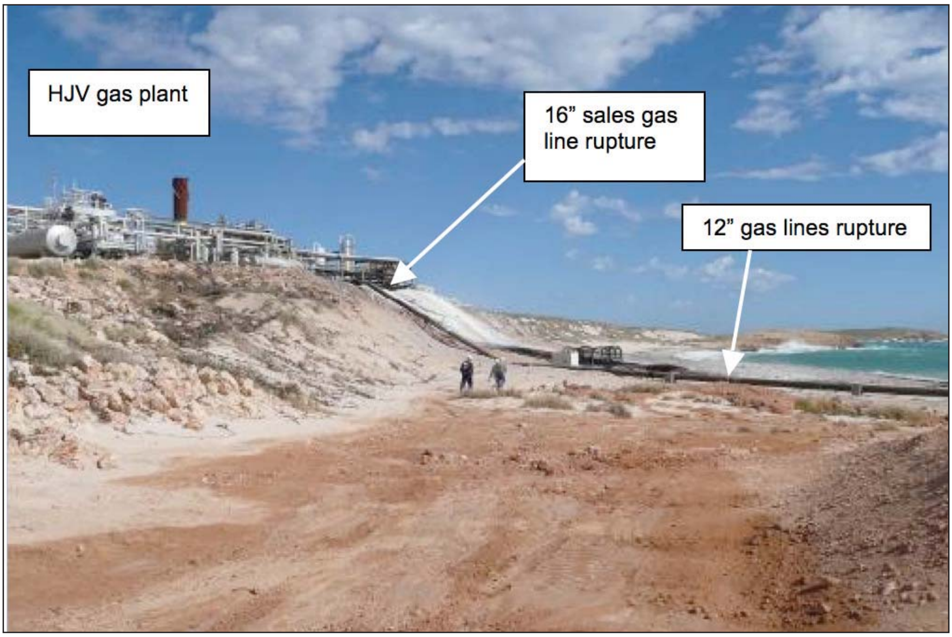
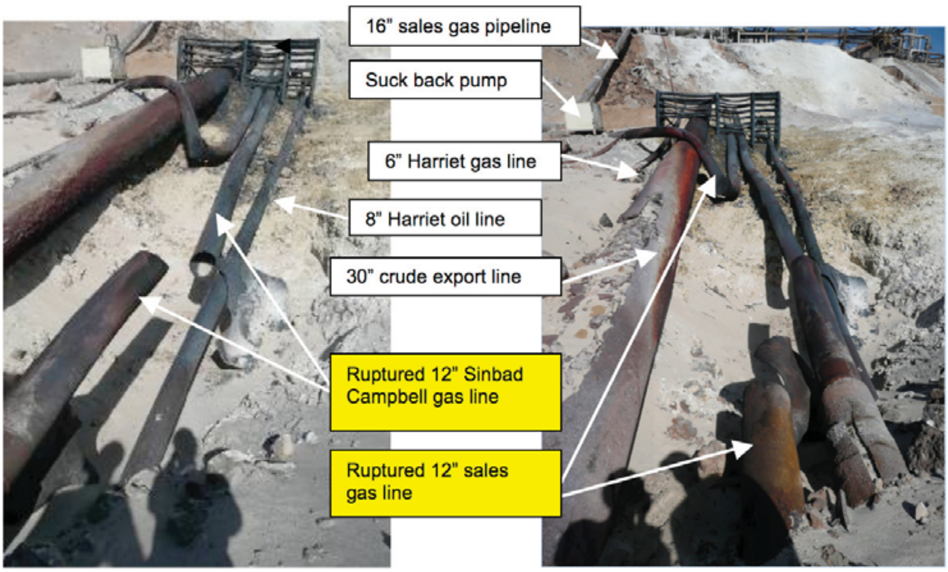


Photo 4 a) & b) – Ruptured 12" pipelines



4 a)

4b)

Photo 5 – Explosion crater

Photo 6 – 30” crude export line valve cyclone protection cage

Photo 7 – Seawall banking

Photo 8 –Damaged gas plant

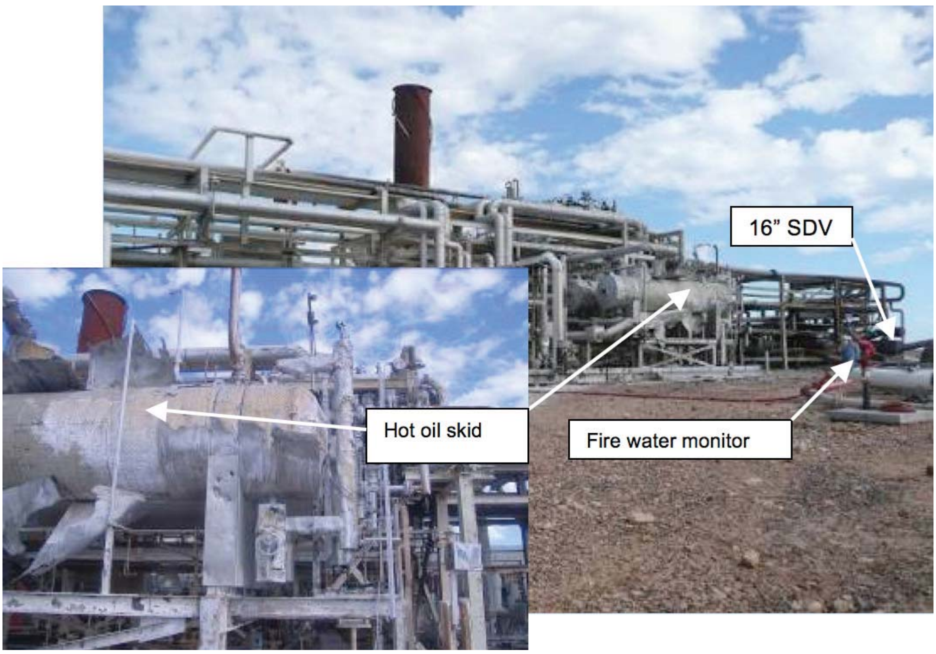


Photo 9 – 16" SDV (gas export line)

Photo 10 – Ruptured 16" sales gas line

Photo 11 – Ruptured 6” Harriet gas line

Photo 12 – Debris in HJV gas plant (compressors) area

Photo 13 – Seawall banking water and jet fire erosion

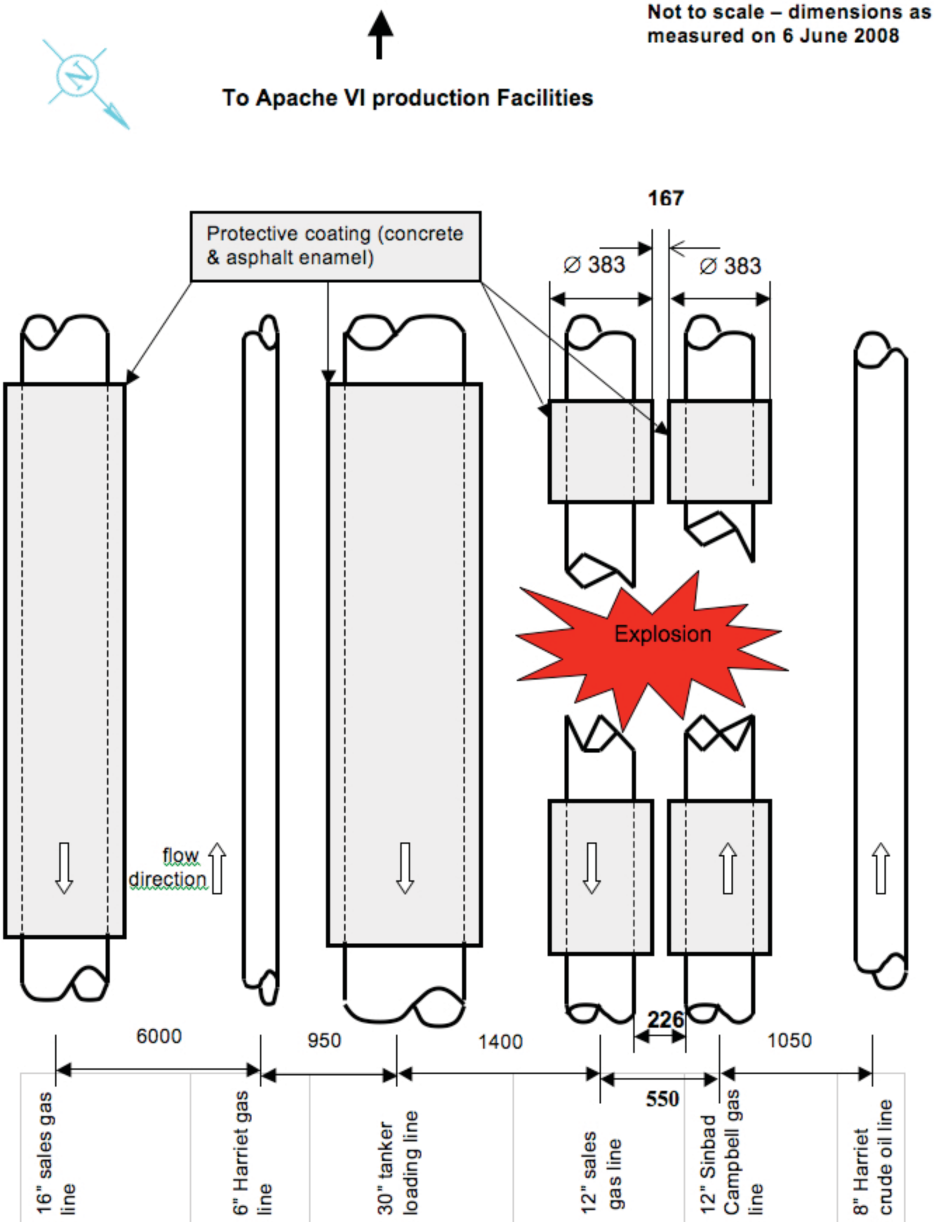
Photo 14 – Ruptured section 12” sales gas line, external corrosion and wall thinning

Photo 15 – Ruptured section 12” sales gas line external corrosion

Photo 16 – Inside view of 16" SDV, ball in closed position

Attachment 6

Sketch 1 – Incident site, pipelines proximity



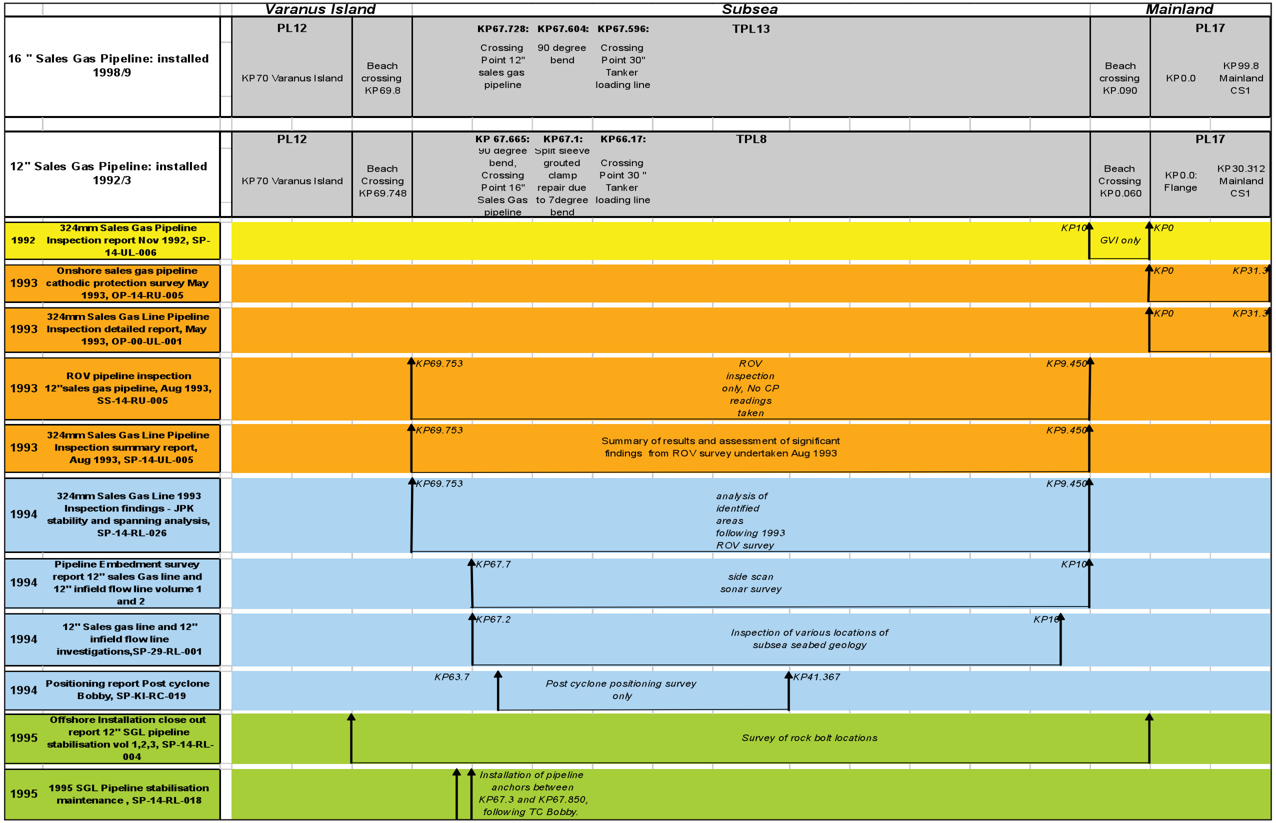
Attachment 7

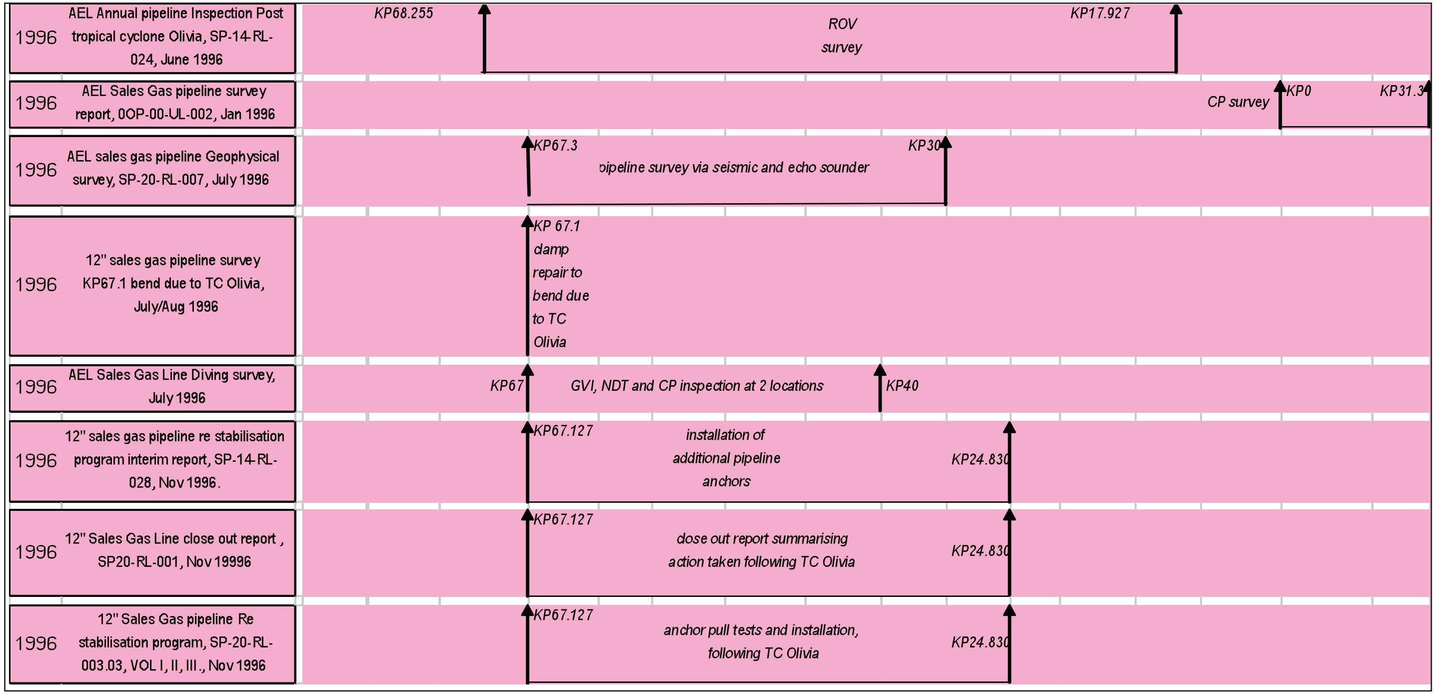
	Last Name	Given Names	Position/Company	Date of Interview	Interview Location
1	Beckford	Peter	Corrosion Technician/ Apache	6 June 2008	Varanus Island
2	Bennett	Zachary James	Construction Superintendent/ Clough	21 July 2008	Clough Perth
3	Davies	Ivor Haora	Scaffolder/Wilson Pipe Fabrication	4 July 2008	CFMEU Perth
4	Drake Brockman	Tony	Instrument Electrical Fitter/Chamber of Commerce and Industry	19 June 2008	WA DoIR Perth
5	Embleton	Brian Kevin	Construction Manager VI/Embo Engineering Ltd	6 June 2008	Varanus Island
6	Fletcher	Wayne Kevin	Process Operator/ Apache	5 June 2008	Varanus Island
7	Jackson	Christopher VanHomngh	Safety Manager/Apache	6 June 2008	Varanus Island
8	Morck	Justin Michael	Production Operator/ Apache	5 June 2008	Varanus Island
9	Paton	Ross Adam	Varanus Island Field Superintendent/Apache	7 June 2008	Varanus Island
10	Simcock	Wayne Douglas	Maintenance Supervisor	5 June 2008	Varanus Island
11	Smith	Gavin James	Electrician/Apache	5 June 2008	Varanus Island
12	Solomon	Paul William	Rigger Scaffolder/Wilson Pipe Fabrication	9 July 2008	CFMEU Perth
13	Symington	Vincent David	Onshore Production Supervisor/Apache	5 June 2008	Varanus Island
14	Thomas	Grant Elliot Te-Tahu-O-Kawatpuarangi	Scaffolder/Wilson Pipe Fabrication	4 July 2008	CFMEU Perth
15	Welten	Mark Anthony	Medic Safety Officer/ Apache	6 June 2008	Varanus Island
16	Wong	Ling Chang (James)	Instrument Technician/ Apache	20 June 2008	WA DoIR Perth

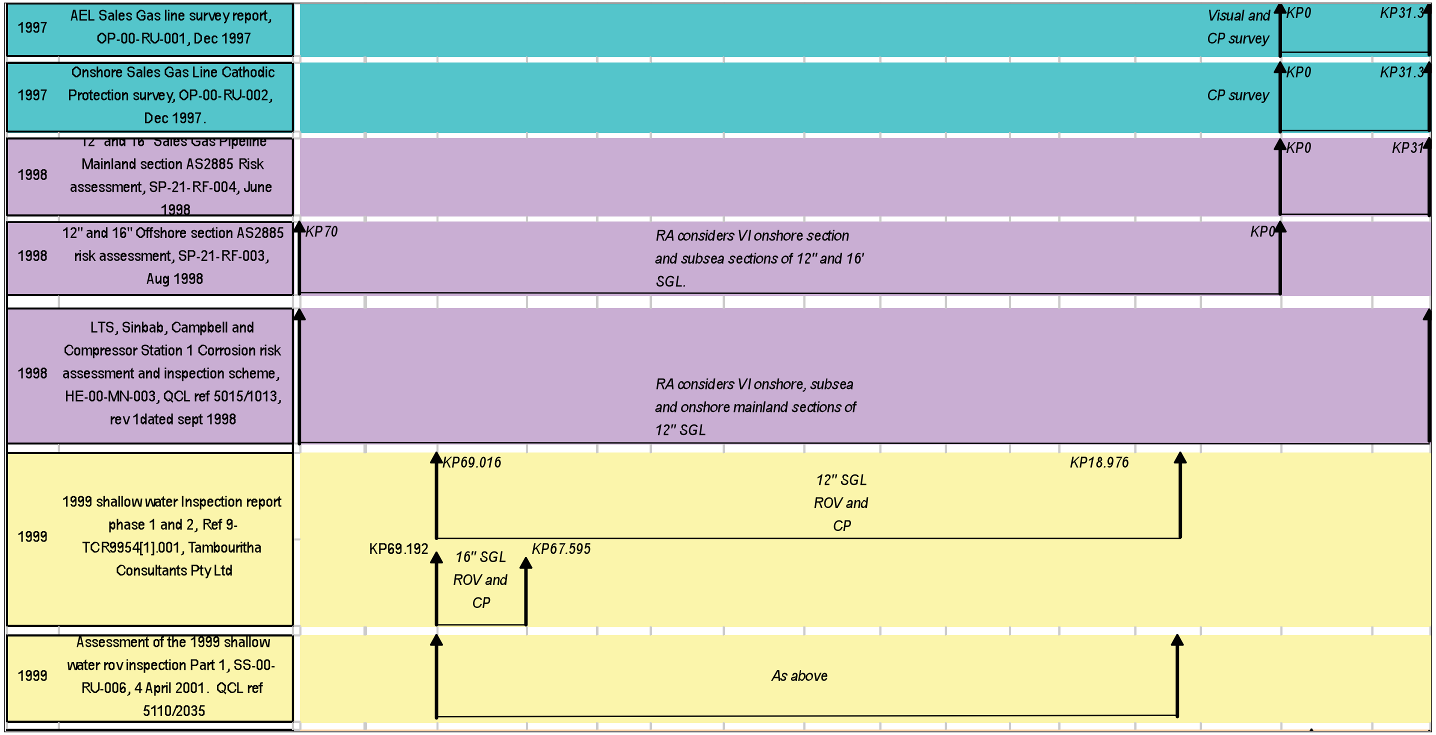
Attachment 8

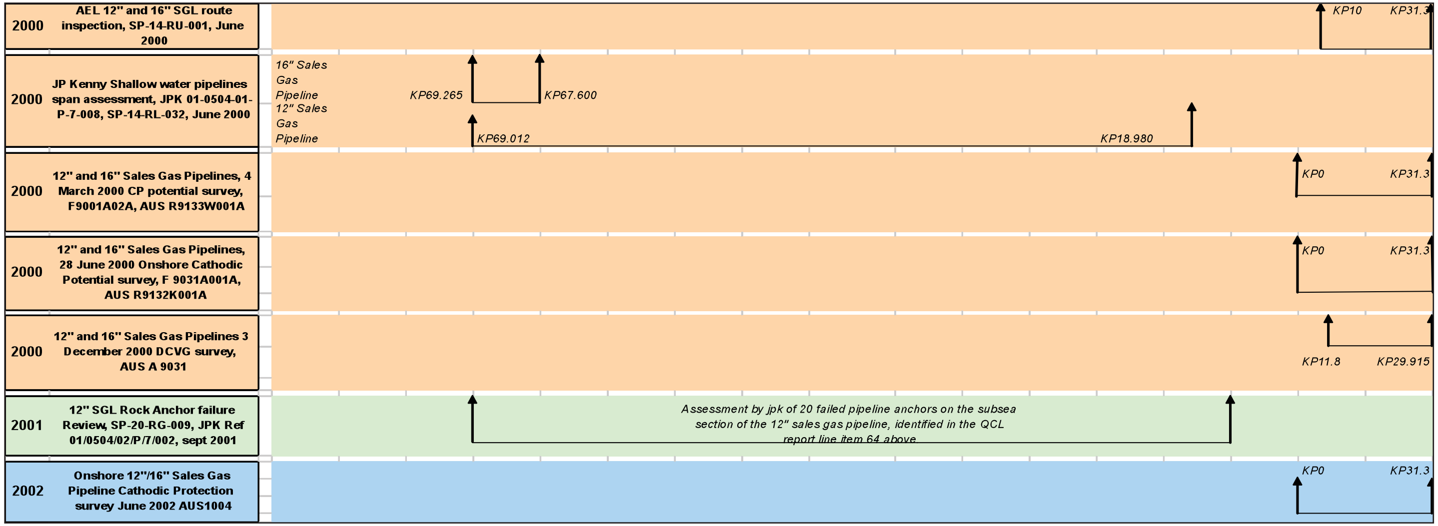
Apache Pipeline IMMR Activities

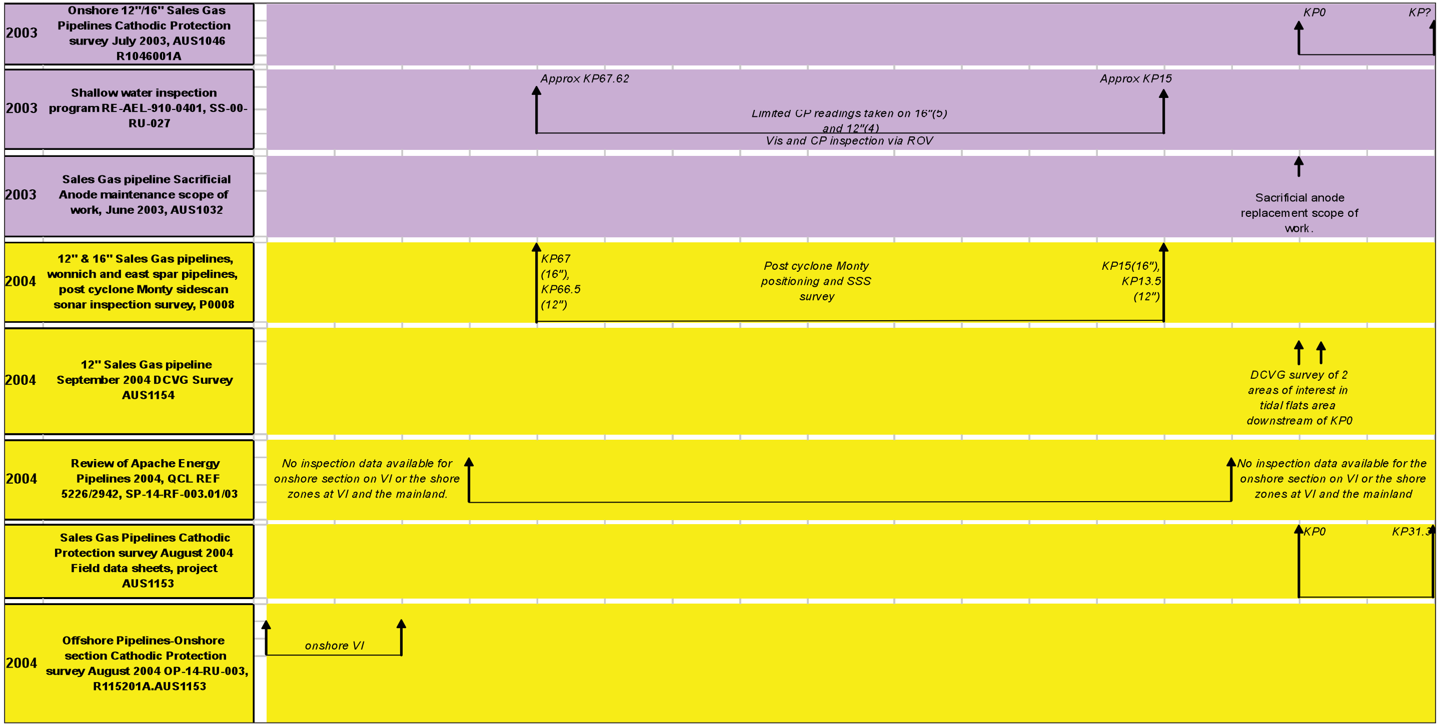
Table 1- IMMR Activities




1996
AEL Annual pipeline Inspection Post tropical cyclone Olivia, SP-14-RL-024, June 1996
KP68.255
ROV survey
KP17.927
1996
AEL Sales Gas pipeline survey report, 0OP-00-UL-002, Jan 1996
CP survey
KP0
KP31.3
1996
AEL sales gas pipeline Geophysical survey, SP-20-RL-007, July 1996
KP67.3
pipeline survey via seismic and echo sounder
KP30
1996
12" sales gas pipeline survey KP67.1 bend due to TC Olivia, July/Aug 1996
KP 67.1
clamp
repair to
bend due
to TC
Olivia
1996
AEL Sales Gas Line Diving survey, July 1996
KP67
GVI, NDT and CP inspection at 2 locations
KP40
1996
12" sales gas pipeline re stabilisation program interim report, SP-14-RL-028, Nov 1996.
KP67.127
installation of additional pipeline anchors
KP24.830
1996
12" Sales Gas Line close out report , SP20-RL-001, Nov 19996
KP67.127
close out report summarising action taken following TC Olivia
KP24.830
1996
12" Sales Gas pipeline Re stabilisation program, SP-20-RL-003.03, VOL I, II, III., Nov 1996
KP67.127
anchor pull tests and installation, following TC Olivia
KP24.830


1997
AEL Sales Gas line survey report, OP-00-RU-001, Dec 1997
Visual and CP survey
KP0
KP31.3
1997
Onshore Sales Gas Line Cathodic Protection survey, OP-00-RU-002, Dec 1997.
CP survey
KP0
KP31.3
1998
12" and 16" Sales Gas Pipeline Mainland section AS2885 Risk assessment, SP-21-RF-004, June 1998
KP0
KP31
1998
12" and 16" Offshore section AS2885 risk assessment, SP-21-RF-003, Aug 1998
KP70
RA considers VI onshore section and subsea sections of 12" and 16' SGL.
KP0
1998
LTS, Sinbab, Campbell and Compressor Station 1 Corrosion risk assessment and inspection scheme, HE-00-MN-003, QCL ref 5015/1013, rev 1dated sept 1998
RA considers VI onshore, subsea and onshore mainland sections of 12" SGL
1999
1999 shallow water Inspection report phase 1 and 2, Ref 9-TCR9954[1].001, Tambouritha Consultants Pty Ltd
KP69.016
KP18.976
12" SGL ROV and CP
KP69.192
16" SGL ROV and CP
KP67.595
1999
Assessment of the 1999 shallow water rov inspection Part 1, SS-00-RU-006, 4 April 2001. QCL ref 5110/2035
As above


2000
AEL 12" and 16" SGL route inspection, SP-14-RU-001, June 2000
KP10
KP31.3
2000
JP Kenny Shallow water pipelines span assessment, JPK 01-0504-01-P-7-008, SP-14-RL-032, June 2000
16" Sales Gas Pipeline
KP69.265
KP67.600
12" Sales Gas Pipeline
KP69.012
KP18.980
2000
12" and 16" Sales Gas Pipelines, 4 March 2000 CP potential survey, F9001A02A, AUS R9133W001A
KP0
KP31.3
2000
12" and 16" Sales Gas Pipelines, 28 June 2000 Onshore Cathodic Potential survey, F 9031A001A, AUS R9132K001A
KP0
KP31.3
2000
12" and 16" Sales Gas Pipelines 3 December 2000 DCVG survey, AUS A 9031
KP11.8
KP29.915
2001
12" SGL Rock Anchor failure Review, SP-20-RG-009, JPK Ref 01/0504/02/P/7/002, sept 2001
Assessment by jpk of 20 failed pipeline anchors on the subsea section of the 12" sales gas pipeline, identified in the QCL report line item 64 above
2002
Onshore 12"/16" Sales Gas Pipeline Cathodic Protection survey June 2002 AUS1004
KP0
KP31.3


2003
Onshore 12"/16" Sales Gas Pipelines Cathodic Protection survey July 2003, AUS1046 R1046001A
KP0
KP?
2003
Shallow water inspection program RE-AEL-910-0401, SS-00-RU-027
Approx KP67.62
Approx KP15
Limited CP readings taken on 16"(5) and 12"(4)
Vis and CP inspection via ROV
2003
Sales Gas pipeline Sacrificial Anode maintenance scope of work, June 2003, AUS1032
Sacrificial anode replacement scope of work.
2004
12" & 16" Sales Gas pipelines, wonnich and east spar pipelines, post cyclone Monty sidescan sonar inspection survey, P0008
KP67 (16"), KP66.5 (12")
Post cyclone Monty positioning and SSS survey
KP15(16"), KP13.5 (12")
2004
12" Sales Gas pipeline September 2004 DCVG Survey AUS1154
DCVG survey of 2 areas of interest in tidal flats area downstream of KP0
2004
Review of Apache Energy Pipelines 2004, QCL REF 5226/2942, SP-14-RF-003.01/03
No inspection data available for onshore section on VI or the shore zones at VI and the mainland.
No inspection data available for the onshore section on VI or the shore zones at VI and the mainland
Sales Gas Pipelines Cathodic Protection survey August 2004 Field data sheets, project AUS1153
KP0
KP31.3
2004
Offshore Pipelines-Onshore section Cathodic Protection survey August 2004 OP-14-RU-003, R115201A.AUS1153
onshore VI

2004	Subsoil pipe coating repair 17-10-04 (P.Beckford report)	KP0.0 Repair to coating damage on 12" and 16" Sales Gas pipelines
2004	Sales Gas Pipeline Cathodic Protection Sacrificial anode testing 13-11-04, AUS1172, L117201A	KP12.112; KP20.2 12/KP2 9.050
2004	VI Ultra Shallow water and onshore pipeline inspection, RE-AEL-916-01 Rev 2, OP-14-RU-002, inspection performed Oct 2004	12" Sales Gas Pipeline; KP68.243; GVI only for 12"
2005	December 2005 CP survey, AUS129901A	KP1.95; KP31.3
2005	2005 Annual Summary report of Inspection and corrosion management activities AE-00-RN-004	Report summarises inspection and corrosion management activities for all assets, including 12"/16" sales gas pipelines, onshore and offshore sections, during the period 2003/2004, and up to
2006	Fugro Report for the post Cyclone ROV inspection, SS-00-RU-038(1), 10th -19th April 2006	16" KP67.5; 16" KP62.915; 12" KP51.330
2006	VI Offshore pipework monitoring18/6/06	cp readings
2006	Onshore 12"/16" sales Gas pipelines onshore section Cathodic Protection survey July/Oct 2006 AUS R137101A	KP0; KP31.3

2007	Sales Gas Pipelines - 5 year integrity review SP-14-RL-067, 30 May 2007.	*Applicable to 12" and 16" sales gas pipelines*
2007	PL12 Varanus Island Validation summary report (Lloyds report) AE-14-RL-003 REVA May 2007.	*Applicable to VI PL12 license area*
2007	12"/16" SGL Onshore section cathodic protection annual survey R151701, August 2007	*KP0.0* *KP31.3*
2007	12"/16" Onshore section DCVG coating survey, R151801, August 2007	*KP10.25* *KP31.3*
2007	VI Offshore pipework monitoring 1/8/07	*CP readings taken onshore*
2007	2007 Onshore pipeline Inspection workbook, sept 2007	*CP and GVI, all pipelines onshore VI*
2007	Moduspec Review of recommendations from 2004 pipeli assessments, 10-4-2007, PAU0060.1 Moduspec Gap analysis of the QCL review of the AE pipelines(2004) with the requirements of AS2885 and th submerged Lands Pipeline Regulations, PAU0060.18, SP-1	*Review Applicable to all AEL pipelines*
2008	VI offshore pipework monitoring MCC building 2008	*CP readings taken onshore VI*

Table 2 – Prescriptive Requirements

		1992	1993	1994	1995	1996	1997	1998	1999
Petroleum Pipelines Act 1969	applicable onshore VI and onshore mainland sections	36A Work Practices: a licensee shall operate the pipeline specified in the licence of which he is the registered holder in a proper and workmanlike manner and shall secure the safety health and welfare of persons engaged in operations in connection with							
		38(b) A licensee shall maintain the pipeline in good condition and repair							
Petroleum Submerged Lands act 1982	applicable state waters sections	97(3) Work Practices: a licensee shall operate the pipeline in a proper and workmanlike manner, and sha secure the safety health and welfare of persons engaged in operations in connection with the pipeline							
TPL8 Licence requirements (12" Sales Gas pipeline subsea section)	**Pipeline Licence issued under PSLA 82 - 26/7/91**	P9: The licensee shall have cause to have carried out **survey of the exposed pipeline anodes at intervals approved by the director**.....a summary of the results of each survey , the recommendations made by a competent corrosion engineer, and the subsequent							
		P13: unless otherwise approved by the director, the licensee shall carry out an **annual external survey of the pipeline after the cyclone season**......The results of the survey shall be lodged with the director and shall include an engineering assessment of t	Annual externa survey	Annual external survey	Annual external survey	Annual external survey	Annual external survey	Annual external survey	Annual external sur

PL12 and variations (Varanus Island)	**PL12, issued UNDER PPA 69 - 9/5/85**	PL12 P7: the licensee shall be responsible for installin and monitoring the cathodic protection test points							
		PL 12 P7: the licensee shall, when required, submit to the director a report in writing outlining the results of th corrosion surveys and the details of any resulting actio by the licensee							
		PL12 P7: the licensee shall carry out an annual extern survey of the pipeline after the cyclone season and th results of the survey shall be submitted to the director writing	annual externa survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey
	PL12 Variation 1/91-2, issued 11/5/92 (12" Sales Gas Pipeline-consistent with TPL8)	the licensee shall be responsible for installing and monitoring the cathodic protection test points							
		the licensee shall, when required, submit to the directo a report in writing outlining the results of the corrosion surveys and the details of any resulting action by the licensee							
		the licensee shall carry out an annual external survey the pipeline after the cyclone season and the results c the survey shall be submitted to the director in writing	annual externa survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey
	PL12 Variation 9P/97-8 (16" Sales Gas Pipeline-consistent with TPL13) issued 30/9/98							The licensee shall maintain and monitor a system, acceptable to the director, for the monitoring and control of corrosion and stress corrosion	
								the licensee shall, when required, submit to the director a report in writing outlining the results of the corrosion surveys and the details of any resulting action by the licensee	
								the licensee shall, within 3 months of the dat of commencement of operation of the pipeline, have cause to have carried out an inspection of the pipelines cathodic potentia and voltage gradient using the close order potential survey techniques, and ther	
								not more than 2 years after the grant of this licence.........and at intervals of not more than five years thereafter...........carry out a **review to determine the likely continued integrity of the pipeline**. The licensee shall within 60 days of finishing this review	
								The licensee shall carry out an external surv of the pipeline route after each major storm activity in order to monitor the integrity of th pipeline	

Pipeline IMM Requirements as per section 8 of the AEL Underwater Inspection Manual AE-00-MG-005	**document issued for use 5/8/05**								
IMM requirements onshore pipeline inspection manual AEL doc OP-14-MG-001, Rev 4, 22/3/06. (originally issued 27/6/97)	applicable for onshore VI and mainland sections of 12"/16" pipeline, between landfall and the pipeline termination/pig launcher/receiver.						Annual inspection frequency to be applied, as per AS2885.3 1997, until the risk based approach introduced in AS2885.3 2001, is adopted. Annual topographical survey in beach zone, annual GVI annual CP, annual line walk, annual surge protection system/sta	Annual topographical survey in beach zone annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.	Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.
AS2018-1981 SAA Liquid petroleum pipeline code	applicable to PL12	12" SGPL installed after this standard was supersedec by AS2885-1987, therefore the applicability of this standard to the 12" SGPL is irrelevant							
AS2885-1987 Pipelines - Gas and liquid Petroleum (the SAA Code)	AS2885-1987 Pipelines- Gas and liquid Petroleum (the SAA Code); applicable to TPL8(12" SGPL), TPL13(16"SGPL),	Section 6.9.3.3(a)Buried pipeline: (i) potential surveys shall be made at intervals of not more than 12 months or where cathodic protection potentials may be affecte by stray DC currents, potential survey intervals shall b approved. (iii) galvanic ano	CP survey	CP survey	CP survey	CP survey	CP survey	CP survey	CP survey
		Section 6.9.3.3(b) Submerged Pipeline: the efficacy of a galvanic anode cathodic protection installation shall be established within a period of not more than 12 months of its installation. The installation shall be monitored at intervals of not more tha	initial post installation CP survey				CP survey		

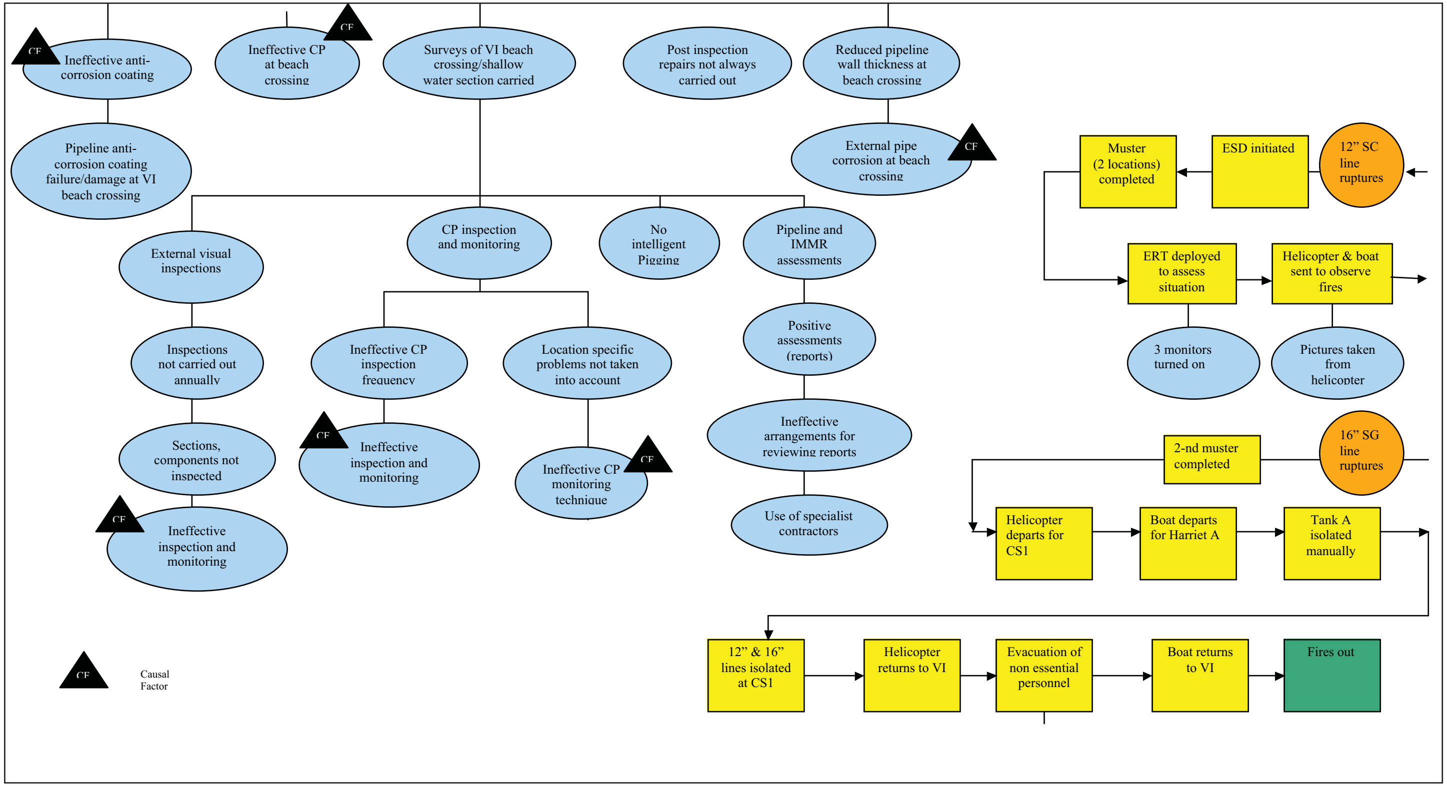
AS2885.3 - 2001 Pipelines - Gas and liquid Petroleum Pt 3 Operation and Maintenance	Onshore pipeline inspection manual OP 14-MG-001, section 2.1, states that the standard provides the justification for implementing the inspection system.								
Offshore Standard DNV-OSF-101 Submarine Pipeline Systems 2000	2000								

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Annual external survey	Annual external survey	Annual external survey	Annual external survey	Annual external survey	Annual external survey	Annual external survey	Annual external survey	Annual external survey	Annual external survey

annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey
annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey	annual external survey
Integrity review					Integrity review				

					Level 1 surveys(side scan sonar): at least every 3 years.		side scan sonar survey		
					Level II surveys (ROV CP and GVI): every 3 years		ROV CP and GVI		
					Level III surveys: shall be carried out following the discovery of suspect defect areas on the pipeline either at the same time as the main survey or as soon as possible after the defect has been found				
					Level IV surveys(inspection by diver, Intelligent pig inspection): level IV surveys by IP shall be carried out at a frequency based on the condition of the pipeline, current knowledge of its condition and the rate of deterioration of the pipeline. The ma				
Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.	Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.	Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.	Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.	Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.	Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.	Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.	Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.	Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.	Annual topographical survey in beach zone, annual GVI, annual CP, annual line walk, annual surge protection system/static earth system inspection.
CP survey	CP survey	CP survey	CP survey	CP survey	CP survey	CP survey	CP survey	CP survey	CP survey
		CP survey					CP survey		

	Inspection as required at a frequency determined by risk assessment. This to be detailed in Safety and Operating Plan. Inspection frequency to be based on past reliability of the pipeline, historical records, current knowledge of its condition, the rate								
eration Inspection and Repair: Section nspection and monitoring philosophy, A500: an inspection and monitoring osophy shall be established, and this shal n the basis for the detailed inspection and nitoring program. The philosophy shall b									
eration Inspection and Repair: Section Pipeline Configuration Survey, B202: a long term inspection program shall be established reflecting the overall safety objective for the pipeline, and shall be maintained/updated on a regular basis									
eration Inspection and Repair: Section Pipeline Configuration Survey: B209: critical sections of the pipeline system ulnerable to damage or subject to major hanges in seabed conditions ie support and/or burial of the pipeline , shall be inspected									
eration Inspection and Repair: Section Inspection and Monitoring of external rrosion, C304: A survey of the corrosion ection system should be carried out withi 1 year of installation									
eration Inspection and repair Section Inspection and Monitoring of internal rrosion, D204: The frequency of internal spections shall be determined based on actors such as criticality of the pipeline, otential corrosivity of the fluid, detectio									


Ineffective anti-corrosion coating
CF
Ineffective CP at beach crossing
CF
Surveys of VI beach crossing/shallow water section carried
Post inspection repairs not always carried out
Reduced pipeline wall thickness at beach crossing
Pipeline anti-corrosion coating failure/damage at VI beach crossing
External pipe corrosion at beach crossing
CF
Muster (2 locations) completed
ESD initiated
12" SC line ruptures
External visual inspections
CP inspection and monitoring
No intelligent Pigging
Pipeline and IMMR assessments
ERT deployed to assess situation
Helicopter & boat sent to observe fires
Inspections not carried out annually
Ineffective CP inspection frequency
Location specific problems not taken into account
Positive assessments (reports)
3 monitors turned on
Pictures taken from helicopter
Sections, components not inspected
CF
Ineffective inspection and monitoring
Ineffective CP monitoring technique
CF
Ineffective arrangements for reviewing reports
2-nd muster completed
16" SG line ruptures
CF
Ineffective inspection and monitoring
Use of specialist contractors
Helicopter departs for CS1
Boat departs for Harriet A
Tank A isolated manually
12" & 16" lines isolated at CS1
Helicopter returns to VI
Evacuation of non essential personnel
Boat returns to VI
Fires out
CF
Causal Factor

Annex 2: Varanus Island incident investigation report of 7 October 2008: analysis and critique

Overview

The initial investigation into the pipeline rupture and explosion/fire incident that occurred on 3 June 2008 at the facilities operated by Apache on Varanus Island were conducted under the auspices of Western Australian Department of Industry and Resources (DOIR) and the provisions of the Western Australia *Petroleum Pipelines Act 1969* (PPA 1969).

NOPSA provided key support to the investigation under its services contract with DOIR, and undertook the lion's share of drafting responsibilities. The full investigation team comprised:

- NOPSA: two lead inspectors as investigators supported by two more inspectors, a team leader and executive oversight
- DOIR: one lead investigator supported by two more departmental officers and executive oversight.

The lead investigators arrived on Varanus Island late on the 4 June to carry out the investigation. It is DOIR's view that their investigator was there to provide powers of investigation under the PPA 1969.

The two lead NOPSA inspectors are recorded in the NOPSA 'CEO's Newsletters', and other areas in the NOPSA web site, as having appropriate qualifications and experience to understand the technical issues posed by a pipeline failure.

One of the inspectors was a pipeline inspector formerly at DOIR with prior experience in the British nuclear industry. The other inspector, a tertiary qualified engineer with extensive and varied industry and legislative experience, also came from a senior operational position in DOIR. It would appear that they had a level of relevant technical and audit experience. Furthermore, NOPSA inspectors undergo nationally recognised training under the 'Australian Qualifications

Framework'. Almost all of NOPSA's inspectors hold qualifications in 'Government Statutory Compliance' (Certificate IV – PSP41404) and 'Government Investigations' (Certificate IV – PSP41504).

After a number of iterations the following terms of reference were agreed for the investigation:

- identify the facts and events relevant to the incident;
- the likely causes of the incident;
- any actions or omissions by the operator of the Varanus Island facility, or its contractors, leading up to the incident and during the incident that may have contributed to the cause of the incident; and
- any potential for injury to persons arising directly from the fire and explosion(s) at the time of the incident.

The Western Australian Government required a final report within three months and, as a result, the investigation report was finalised on 7 October 2008 and released by the WA Minister on 10 October. The report states that the investigation did not include actions or omissions by any regulator, in particular DOIR, regarding assessment of the appropriateness of the DOIR consents and approvals issued to the pipeline licensee with respect to the Varanus Island plant and associated licensed pipelines. The terms of reference also excluded damage assessment and post incident events, unless they were directly relevant to the focus of the investigation.

The PPA 1969 makes no provision to allow investigators to interview persons and require them to answer questions. However, subsection 63(1) of the Act empowers appointed investigators:

- to enter a licence area;
- to inspect and test any pipeline;
- to take samples of any substance being conveyed in the pipeline; and
- require a licensee, or any other person who has custody of any book, record, document, maps or plans relating to a pipeline to produce them for inspection and copying.

A person who is the occupier, or person in charge, shall provide an inspector with reasonable facilities and assistance for the effective exercise of his inspection powers and a person shall not, without reasonable excuse, hinder the inspector. The penalty is up to $5,000.

At the time of the investigation, NOPSA did not have any inspection or regulatory powers on Varanus Island.

The investigation Terms of Reference

The primary purpose of an OHS investigation is to gather evidence to determine whether the party under investigation has breached OHS law. Where evidence shows that there has been a breach, and the decision is made to prosecute, a brief of evidence is submitted to the Director of Public Prosecutions.

The Terms of Reference for this investigation, however, were broader than an OHS investigation as was possible under the PPA 1969. The scope for this investigation, as outlined in these Terms of Reference, stated the investigation would address:

- The pertinent sequence of events on Varanus Island during the Incident
- The likely cause(s) of the incident
- Any actions or omissions by the operator of the Varanus Island facility, or its contractors, leading up to the Incident and during the Incident that may have contributed to the cause of the Incident
- The identification of any potential injury to persons arising directly from the fire and explosion(s) at the time of the Incident.

The Terms of Reference also indicated that the investigation would be conducted in the context of, and would have regard to, good industry practice, the commitments made by the operator in respect of its operation of the Varanus Island facilities and in the context of the applicable laws and licence requirements.

The investigation into the Varanus Island pipeline rupture and fire

The DOIR/NOPSA investigation into the pipeline rupture and fire on Varanus Island was severely restricted in that the investigators' powers to gather evidence was limited to subsection 63 (1)(d) of the PPA 1969. As a result, they could not compel witnesses, or the operator's staff, to answer questions.

DOIR[139] submitted that, although the investigation was conducted under its legislation and submitted to the department, they considered that the report contained errors and omissions. The department also stated that they had asked for a number of changes to the final report but these were not accepted by NOPSA. With respect to the report, DOIR considered that:

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- three of the conclusions reached by NOPSA were not fully substantiated by evidence;
- conclusions were potentially contradictory; and,
- 'Finding 38' suggests that NOPSA did not delve deeply enough or use correct questioning techniques regarding the maintenance history of the 12 inch SGL.

Because of these errors and omissions, DOIR did not consider the report adequate for prosecution purposes.

NOPSA disputed this and pointed to an email from the Director PRD of DOIR stating that 'the report is generally acceptable and in accordance with the terms of reference.'[140] Further, NOPSA asserts that out of the 'small number' of changes were proposed by DOIR, those changes relevant to the terms of reference were adopted, and valid reasons were given for not adopting the remainder. NOPSA also noted that the decision to consider the report as 'Final' was made by DOIR, which advised that any additional information would be dealt with as an addendum.

It is important to note that the investigation was not primarily aimed at understanding a system that had failed with a view to preventing similar incidents. The primary purpose was to investigate under the terms of reference and determine whether or not the provisions of the WA PPA had been breached. The report, in fact, identified two possible breaches of the WA PPA and one breach of the subordinate regulations. The operator, if convicted of the alleged breaches, faces a total possible fine of $100,000 under the Act and a further $2,500 fine under the associated regulations.

The report to DOIR noted:

> *There are aspects of some lines of investigation that have not been settled, principally due to the delay by Apache in providing information and delays in forensic testing of pipe samples.*
>
> *In particular:*
>
> - *completion and full analysis of the forensic testing of pipe samples;*
> - *statements from key personnel (Apache on behalf of its key personnel declined requests for interview); and*
> - *identification of special technical details relating to the cathodic protection of the 12 inch SGL.*[141]

140 Email from Bill Tinapple (DOIR) to Simon Schubach, dated 3 October 2008

141 Ibid, Varanus Island Report p.4

Therefore, due to limitations of the investigators' powers, and the implied deadline, the report was incomplete.

Apache restricted the personnel available for interview. However, the company did assist the inquiry to the extent that it was required to do so by the WA PPA. It should be noted that there is no incentive for an operator to assist a punitive inquiry beyond that strictly required in legislation.

Limitations of the DOIR/NOPSA Varanus Island Report

Although titled 'Final Report' the report authors point to a number of outstanding issues that had not been settled. In particular:

- Completion and full analysis of the forensic testing of pipe samples;
- Statements from key Apache personnel (Apache on behalf of its key personnel declined requests for interview; and
- Identification of specific technical details relating to the cathodic protection of the 12 inch SGL.

Apache, in responding to the 'Final Report', expressed disappointment and surprise at the report's conclusions. Apache specifically referred to the NOPSA media release of 18 June 2008 which stressed the complex and technical nature of such an investigation and the importance of conducting a thorough and proper analysis. The media release continued:

> *It would be inappropriate to pre-empt the findings and recommendations by releasing any investigation material prior to its completion and proper consideration by the appropriate authorities and government. Generalised speculation regarding the causes of the events may compromise the ability of the investigation team to complete its work.*[142]

There was no real investigation of the mode of failure other than to attribute it to ineffective anti-corrosion control. If proved, this may secure a conviction based on a duty of care to maintain the pipeline in a manner that ensures that it does not pose an unacceptable risk to people and/or is kept in good condition and repair.

The investigation did not delve deeply to provide an understanding of the mechanics behind the cause of the external corrosion. Apache makes the point in their response to the 'Final Report' by highlighting that the investigators stated:

142 NOPSA Media Release 18 June 2008

the evidence available to date is insufficient to determine why the corrosion coating may have failed. Apache contends that it is essential to establish whether the corrosion coating failed and, if so why. Any investigation into the cause of the explosion that fails to consider this issue is deficient.

The 'Final Report' did not discuss the related issues of the spacing of the pipelines at the beach crossing or the possibility that the 12 inch SGL had acted as a sacrificial anode to adjacent pipes. Corrosion may have occurred rapidly in this manner or perhaps because excessive cathodic protection current led to disbonding of the anti-corrosion coating. The investigators preferred the explanation of 15 years of corrosion based on an expert's opinion.

NOPSA representatives stated that the possibility of corrosion through steel sacrifice to adjacent pipelines was considered but seen as 'esoteric' and not material to the investigation's remit. It was NOPSA's view that consideration of the issue in depth would have delayed the report and that the report had already established prime facie evidence of maintenance failure, a breach of the Act and regulations.

NOPSA's approach to the investigation may have been influenced by the fact that as an OHS regulator, it would usually conduct investigations for the purpose of detecting OHS breaches only. In the case of this investigation, the Terms of Reference asked for more.

Regardless of these considerations, a proper understanding of the failure mode would also assist industry in preventing similar incidents in the future and possibly help in shaping future regulation.

Sed quis custodiet ipsos Custodes?[143]

The investigators did not consider the roles of their own organisations, DOIR and NOPSA. There was no specific direction to exclude the role of the regulators, although it was not specifically included either. In addition, the timescale imposed by the WA Government may have been at issue.

Either way, the deficiencies and gaps revealed by this inquiry should have manifested themselves. Exposure of the deficiencies and gaps in the regulatory oversight may have been seen as diluting any potential culpability on the part of the operator. However, critical self-examination and redressing the deficiencies reduces the risk of similar future occurrences on other facilities.

While recognising the limitations of the DOIR legislation and the role of enforcement entrusted to OHS regimes and given the very limited

143 But who guards the guardians themselves: Juvenal

fines that could have been imposed, a more safety orientated approach in a public report would have better served the offshore industry and the Western Australian public.[144] While creditable in the timescale, the investigation report failed to address fully its terms of reference.

An investigation under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006*

The DOIR and NOPSA investigators were significantly hamstrung by the limitations that the WA PPA imposed on the investigation. Amendments to the WA PPA had been passed by Parliament but had not been proclaimed because supporting regulations had not been drafted. The investigation provisions contained in the amendment (which have not yet come into operation) closely mirrored the powers invested in NOPSA investigators operating within the jurisdiction of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGSA) and substantially increased the monetary penalties for breaches of 'duty of care'.

A NOPSA inspection may include an investigation or inquiry into a breach of the provisions of the OPGGSA[145]. The NOPSA investigation guidelines provide that an investigation may be preceded by a preliminary enquiry to enable a decision to be made on whether to investigate. It should be noted, however, that there is no specific provision for a 'preliminary enquiry' within the legislation. When an investigation is conducted, the enforcement outcomes may be administrative (Improvement Notice or Prohibition Notice) or a criminal prosecution.

NOPSA investigators may, at any time on their own initiative or if directed by the authority, conduct an inspection to ensure legislative compliance: to determine any contravention of OHS law; or into an accident or dangerous occurrence or fatality. Inspectors have very extensive search and evidence gathering powers, exercised with the operator's permission or under a warrant issued by a magistrate. They also have extensive powers to require assistance and, in particular, to require answers to inspectors' questions. A person is not excused from answering a question

144 Note: One way of addressing the need for timely and transparent reporting is for a stepped approach. An initial preliminary report may be issued after a month and an interim factual report within 3 to 6 months before the issue of a final report covering all relevant levels/factors in the system.

145 *Offshore Petroleum and Greenhouse Gas Storage Act 2006*, Schedule 3, Part 4 - Inspections

or from producing a document or article on the grounds that the answer, document or article may tend to incriminate the person or make the person liable to a penalty. But any such information is not admissible in civil or criminal proceedings.

The ‘NOPSA Investigation Handbook’, advises that inspectors should first ask the interviewee to provide information on a voluntary basis. Information provided in this way (voluntarily) is not protected by self incrimination provisions of the OPGGSA. Only when an interviewee refuses to answer questions are the compulsion powers of the OPGGSA used. The protection against self incrimination also triggers ‘derivative use immunity’ which renders inadmissible any information, document or thing obtained as a direct or indirect consequence of answering the question or producing a document or article. The powers provided under the OPGGSA are more appropriately provided to a safety investigation organisation like the ATSB, rather than an OHS regulator.

NOPSA’s powers must be used to the highest investigative and ethical standards and OHS inspectors take note of the *Public Service Act 1999* and the ‘Code of Conduct for Public Servants’. The Code requires that public servants ‘disclose, and take reasonable steps to avoid, any conflict of interest (real or apparent) in connection with APS employment’.

The Apache response to the DOIR Varanus Island report claimed that NOPSA had a clear conflict of interest due to the involvement of key NOPSA regulatory personnel in the investigation. The Varanus Island Investigation included NOPSA team members who had commented on and accepted the facility’s safety case and conducted OHS audits by reference to it. NOPSA has stated that it considered potential conflict of interest concerns very seriously and determined that the required technical capabilities and short time scale warranted the involvement of these team members in the investigation. It was therefore a considered decision to deploy the most appropriately qualified inspectors to the investigation team, taking into account technical expertise and familiarity with the facilities on Varanus Island. In addition, NOPSA has emphasised that the significant senior management involvement and DOIR direction during the course of the investigation ensure that there was no unmanageable conflict of interest in this case.

The 'Stop Rule'

In all investigations, regardless of purpose, there is a place where avenues of investigation must be terminated. Various accident theorists (Rasmussen, Reason, Hopkins, et al) have addressed the concept of the 'Stop Rule'. Where the termination of an avenue of inquiry occurs will depend upon the purpose of the investigation. For example, NOPSA investigations:

> *…(will) continue until the RSA decides that the use of more resources is not justified.*[146]

Ideally, the purpose of an 'in-house' company investigation is to examine the company systems and procedures and introduce remedial action at the appropriate levels of management and operation within the existing regulatory framework. In their response to the 'Final Report' Apache stated that they had *'sought to co-operate with DOIR to identify root cause(s) of the explosion and to try and ensure that this type of incident does not occur in the future.'* While this is an entirely appropriate sentiment it is hard to see how cooperation, which would require total openness on the part of both the operator and regulator, could be accommodated in a regulatory enforcement framework and in the face of possible litigation.

The purpose of a criminal or regulatory compliance investigation, such as police or OHS authorities conduct, is to establish that there has been a breach of law. Safety investigations, however, drill beyond company considerations and legal issues to examine a whole-of-industry system.

The questions become, where does an investigator 'stop' a particular line of inquiry? And, where does an investigation 'stop'? One answer offered is that the investigator stops when continuing will make no difference to the investigation findings. In the case of a company investigation, this is usually where a safe regime of work is restored and identifiable risks are mitigated (to ALARP). In a criminal or regulatory compliance investigation the 'stop' point is reached when a breach of the law has been proved for the purposes of a brief of evidence to the Director of Public Prosecutions. With respect to this issue, Hopkins notes:

> *For governments, on the other hand, it makes sense to go one step further and ask whether a failure of the regulatory system was the root cause, for this is a matter which governments can do something about.*[147]

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146 NOPSA Investigation Handbook, 2.7

147 Hopkins, A. (2000) *Lessons from Longford, The Esso Gas Plant Explosion*, Sydney: CCH Australia Ltd, p.17.

The DOIR/NOPSA investigation was limited in its scope. It specifically 'stopped' at a point where possible breaches of the WA PPA and subordinate regulations had been established.

Had the event fallen under NOPSA's jurisdiction with the authority's wider powers available to prove breaches of legislation, it is still likely that the underlying causes of the event would not have been investigated.

This is not to suggest that possible breaches of OHS legislation should not be subject to a criminal or compliance investigation.

It is important to remember that normally under the duty of care or co-regulatory regime a breach of the safety case is a breach of legislation. Where a failure in the safety case and its associated safety management system is so egregious that lives are recklessly put at risk there must be a consequence that imposes a penalty on any perpetrator to deter similar actions by others. However, in this case the safety case on Varanus Island was only part of a PL12 pipeline licence condition under the WA PPA.

Further, OHS investigations do not necessarily address the underlying issues. Other than the loss of reputation, the possible fine would not seem to be a significant deterrent.

In the event of a fatality, a brief is also prepared for a Coroner. Although the Coroner establishes cause of death and may make recommendations to prevent a similar event in the future, the proceedings are often delayed, sometimes for years. The proceedings are also often emotive and adversarial in nature.[148]

Inquires into major incidents which include a reference to the legislative framework often take the form of a public, judicial inquiry. The findings of such inquiries are typically authoritative. However, judicial inquiries are expensive and although inquisitorial in theory, are often adversarial in their proceedings. Witnesses are often subject to forensic cross examination whether or not they have some responsibility for the incident. This adversarial nature often leads to counsel seeking to discredit witnesses on behalf of their clients rather than assisting the inquiry to understand what made sense to the people involved at the time[149] and what changes to the system should be made to improve safety for the future.

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148 Walker, M. & Bills, K. (2008) *Analysis, Causality and Proof in Safety Investigations*, Canberra: ATSB

149 Turner, B. (1987) *Man-Made Disasters*

Apache's critique of the DOIR/NOPSA incident investigation report

On 10 October 2008, the day the WA Minister released the incident investigation report by DOIR that was completed on 7 October, Apache released a critique. While Apache's critique was, of course, after the 3 June 2008 incident, it indicated the operator's views on a number of issues. A more considered response to the report by Apache was completed on 6 February 2009.

Apache is repeatedly very critical that the DOIR/NOPSA investigation report was released as a 'final report' before final metallurgical assessment, including destructive testing results, had become available. Apache states that the corrosion on the 12 inch SGL:

> *...did not even cover the entire circumference of that portion of the line ... There is no evidence that cathodic protection was failing along the pipeline ... the entirety of the nearly identical 12" Sinbad-Campbell line ... suffered no such corrosion...*

The 12 inch Sales Gas pipe metal loss at the shore crossing from over 11 mm to less than 4 mm covered a section of the pipe large enough so that the rupture caused an explosion and jet fire.[150] The existence of such external corrosion is evidence that cathodic protection (CP) had not protected a section of the pipe where the anti-corrosion coating had disbonded. There are at least two plausible scenarios under which CP may have been a major contributing factor to the corrosion at an accelerated rate. One is the 12 inch SGL effectively acting as a 'sacrificial anode' to an adjacent pipe and another is excessive CP voltage causing disbonding which then shields the pipe from further CP protection and enables a corrosion cell to operate under the coating. The DOIR/NOPSA report indicates at page 19 that Apache is incorrect to claim that the adjacent Campbell-Sinbad pipe suffered no corrosion.

Apache is very critical of the NOPSA OHS inspectors' investigation role as they are said to lack relevant competencies and also had been involved in past audits of the Apache facilities and therefore arguably had a 'conflict of interest'. Apache suggests that because the inspectors did not question the integrity of the line before the explosion, this 'indicates the explosion was unforeseeable'. However, other explanations are that a standard sampling audit process had not included this section of pipeline yet, or even that inspectors had failed to question integrity when they should have done so. Apache stated that 'Apache remains focused on determining the complex and precise cause of the explosion which was highly unusual and

150 Apache is critical of the DOIR/NOPSA report for terming this thinning as 'significant' because Apache argues that this term 'is subjective and scientifically meaningless'.

not reasonably foreseeable'. Apache has not acknowledged its own conflict of interest especially in a context of seeking to minimise the risk of prosecution and other litigation.

Apache repeatedly cites the Lloyd's Register Validation Summary Report dated 10 May 2007 in support of its view that it was entitled to believe the 12 inch SGL was fit for purpose for another 21 years. It criticises the DOIR/NOPSA report because 'the report refers to a single sentence of a report by Lloyd's ... about manning levels'. However, as outlined above, this summarised one of two detailed final recommendations by Lloyd's which were backed by substantial documentation in an earlier Lloyd's Register Stage 3 report dated 20 December 2006.

While there was no regulatory requirement to intelligently pig the 12 inch SGL, in a duty of care/safety case regime Apache is responsible for ensuring safety and integrity to ALARP levels consistent with good oilfield practice. It is not enough to rely on a regulator's requirements to provide integrity assurance. In a safety case regime it is unambiguously the responsibility of the operator to determine the adequacy of its integrity plan.[151] Other operators in Australia and internationally were intelligently pigging pipelines to assess any excessive metal losses from corrosion and Apache was itself doing so in some circumstances.

While Apache says it is seeking to establish root cause, we believe it is most unlikely to publicise anything that could compromise its legal position in any future litigation. The DOIR/NOPSA investigation was focussed on seeking any breaches of legislation rather than establishing root causes and in any case did not look at any regulatory aspects that may have been relevant. International and Australian best practice is to legislate to create a properly resourced independent safety investigator that is able to compel documents and witness statements and establish root causes and contributory factors through a systemic investigation that only seeks to enhance future safety. The quid pro quo for such powers, as under the ATSB's *Transport Safety Investigation Act 2003*, is that such investigation reports and the evidence underpinning them held by the investigator cannot be used in civil or criminal courts. Any regulatory or police investigation is quite separate.

151 However, as noted in our main report, WA does not have a full safety case regime and the Varanus Island safety case was a condition of the PL12 licence.

An investigation framework for the 21st Century

A significant number of governments have introduced an independent inquiry of an administrative nature whose aim is to establish safety outcomes by investigating transport accidents and incidents without attributing blame or assigning liability.

> *… independent accident investigation may yield important benefits. The reason for an accident may lie in flawed policy-making, or in failings in either the setting or policing of safety standards. Accident investigators must not feel constrained in considering such possibilities.*[152]
>
> *The public (and especially the survivors and the relatives and friends of those who lost their lives) has a legitimate interest in learning the truth of what happened, without anything being swept under the carpet.*[153]

Safety organizations such as the United States' NTSB, Canada's TSB, the Dutch Safety Board, New Zealand's TAIC, and Australia's ATSB[154] are staffed by trained safety investigators who are specialists in the various transport modes' failure analysis, organisational structures and human factors. The reports issued by these bodies are independent of operators and regulators, authoritative and solely aimed at preventing future accidents and incidents.

The formation of independent multi-modal or specialist investigation bodies does not rule out other forms of inquiry. Nor does it remove the need for investigating breaches of the law with a view to prosecuting reckless or egregious acts or omissions on the part of individuals or companies.

However, entrusting such investigations to an independent, expert, specialist safety investigation body is a safeguard against withholding from exposure unpleasant or uncomfortable factors. Had such a body been inexistence the difficulties we faced in obtaining documents from the operator would have been overcome.

152 Home Office (UK), (1997) *Report of the Disasters and Inquests Working Group*, Part 2, para 2.22

153 Clarke, LJ, *Thames Safety Inquiry*, Final Report, 1999, para 5.3

154 A brief outline of the aims of an ATSB investigation are contained in Annex 14 of this report.

Annex 3: Townend metallurgical report

Varanus Island 12” Sales Gas Line Examination of Samples

Report number: PHT/DIR/04/09

Client: Department of Mines and Petroleum

Client Contact: Shayne Sherman

Date: April 2009

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1. Introduction

This report presents observations and test results by the author and others on a burst region of 12” Sales Gas line removed from Varanus Island after the 3 June 2008 explosion and fire. The primary piece from the origin of the burst had been marked with the identification 12-SG-N-FE.

The objective of this report was to comment on the physical properties of the pipe material and compare them against applicable codes and standards.

I have relied on some information in the following documents that were made available to me;

NOPSA Introductory Material including Apache Pipelines Design and Operating Parameters

Pearl Street Report 8A5-MET19

Pearl Street Report 8A5-MET21

Pearl Street Report 9A5-MET2 with Appendices 1 to 10

Pearl Street Report 9A5-MET3 with Appendices 1 to 7

Pearl Street Report 9A5-MET4 with Appendices 1 to 6

Pearl Street Report 9A5-MET5 with Appendices 1 to 9

2. Applicable codes and standards

The following standards were considered to be applicable to the 12” Sales Gas line.

2.1 Pipe Material

API 5L Specification for Line Pipe
Grade X60

X60 Required Tensile Properties

Minimum yield strength	= 414 MPa
Minimum tensile strength	= 517 MPa

2.2 Design and Construction

AS2885.1	Pipelines - Gas and liquid petroleum Part 1: Design and Construction

2.3 Operation and Maintenance

AS2885.3	Pipelines - Gas and liquid petroleum Part 3: Operation and Maintenance

2.4 Supplied Pipe Dimensions & Pressure

Outside diameter	= 323.9 mm
Nominal wall thickness	= 11.1 mm
MAOP	= 14.5 MPa
Current operating pressure	= 9.168 MPa

3. Observations and measurements

3.1 Visual Inspection

I took the following photographs of the sample 12-SG-N-FE on 5 August 2008 at the premises of Pearl Street, Welshpool.

Figure 3.1.1
General view of the inner surface of the 12-SG-N-FE piece of pipe, unwrapped by bursting

The once cylindrical length of pipe had been unwrapped and flattened by bursting to become a sheet of pipe steel.

I measured the length of the sheet to be approximately 1.3 m and the width, originally the pipe circumference, was approximately 1 m. The internal surface was observed to be smooth and coated in blue/black and red oxides characteristic of hot oxidation. Also, there were signs of recent ambient temperature corrosion or rusting.

Figure 3.1.2
Closer view of one corner of the approximately rectangular sheet of pipe steel

Reference positions were observed to have been marked in red by others at 100 mm intervals around the perimeter of the sheet.

Figure 3.1.3
External surface of 12-SG-N-FE

Surface roughness characteristic of long term corrosion was observed in a band approximately one third of the width of the sample adjacent to the left hand edge visible in figure 3.1.3. A similar band was observed adjacent to the right hand edge. The colour of the products of corrosion formed by the longer term corrosion were dark brown.

Patches of red oxide colouration also were evident on the external surface. Additionally, there were areas of superficial recently formed light brown rusting.

The external surface of sample 12-SG-N-FE contained less area of hot oxidation products than the internal surface.

I also took close up photographs of corrosion and fracture surfaces. One such close up photograph is shown in figure 3.1.4.

Figure 3.1.4
Close up view of part of the left hand edge showing corrosion pits and a chisel edge at the arrow, adjacent to the position marked 1.1 in red

The fracture surface chisel edge thickness, measured by steel tape, was of the order of 1 mm.

3.2 *C Scan Thickness Measurements*

I observed the sheet 12-SG-N-FE being mapped for thickness on 2 mm x 2 mm squares. The equipment being used was the UK Atomic Energy Authority (AEA) ultrasonic C scan known as μ map.

Figure 3.2.1
General view of thickness mapping of 12-SG-N-FE by Applus RTD personnel

The equipment measures the time for a pulse of ultrasound to travel through the steel from the transmitter probe, reflect from the backwall or opposite face then be detected by the receiver probe. The transit time varies according to thickness of the material and can be calibrated to determine material thickness. Computer software in the instrument converts the transit time to wall thickness, then displays the thickness value as a coloured pixel. The position of the probe on the workpiece is determined by an infrared transmitter on the rear of the probe and an infrared camera clamped onto the workpiece.

The size of the probe prevented measurements being taken any closer than 5 mm from the edge of the sheet.

Figure 3.2.2
Normal or zero degree transmit/receive compression wave probes (1) and position tracking camera (2)

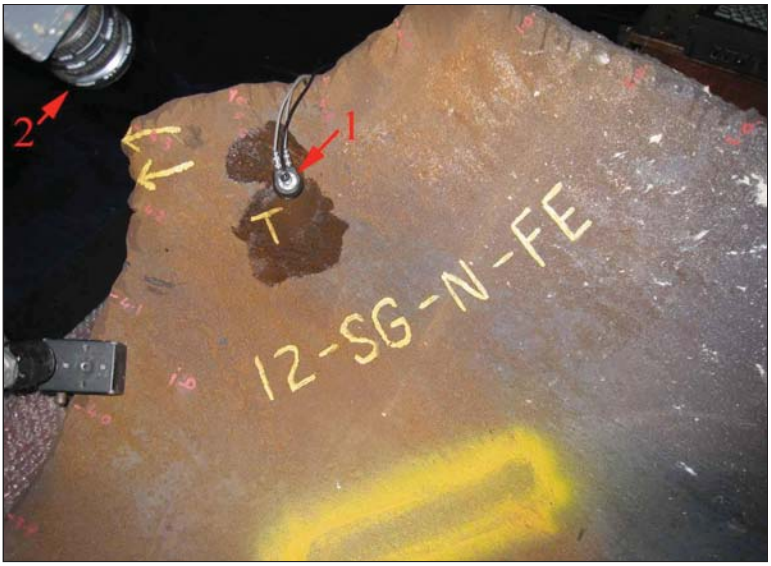
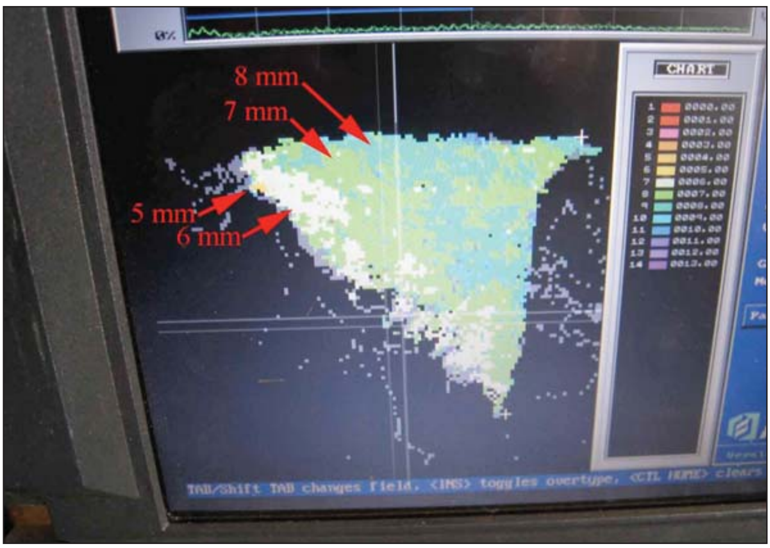


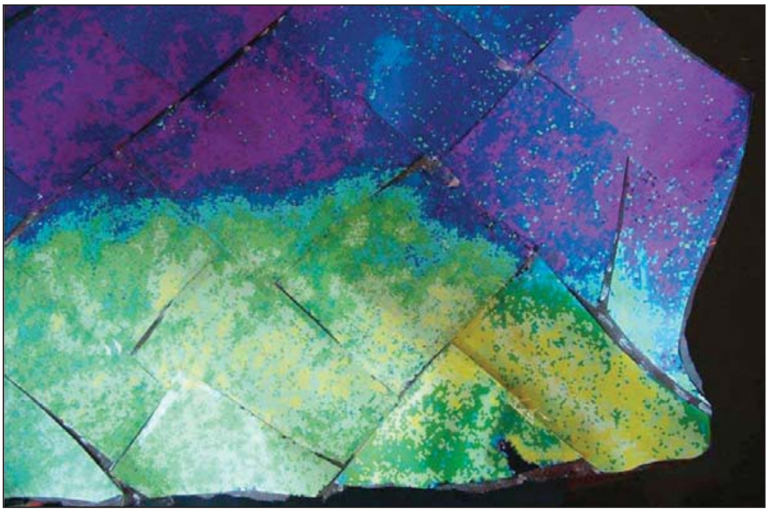
Figure 3.2.3 shows one of the μ maps from sample 12-SG-N-FE. I have marked four different sheet thicknesses on the pixel map using the key shown below the word CHART.

Figure 3.2.3
Monitor screen display showing thickness readings displayed as 2 mm x 2 mm coloured pixels



The thickness maps were printed full size on white paper then the prints were cut and attached to the pipe steel.

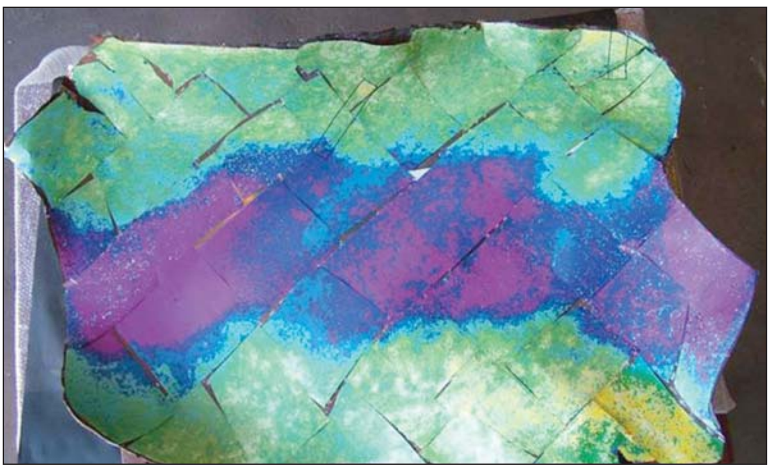
Figure 3.2.4
Colour prints of a set of μ maps attached to the surface of the 12-SG-N-FE pipe piece



The thinnest positions in yellow can be seen towards the bottom right of the photograph.

The process of thickness mapping, colour printing and attachment of the prints to the steel was carried out until all of the sheet of pipe steel had been covered, except for the inaccessible 5 mm strip adjacent to the lines of fracture.

Figure 3.2.5
Colour prints of all μ maps attached to the 12-SG-N-FE piece of flattened pipe



3.3 *Metallographic Sectioning*

I photographed sections of 12-SG-N-FE at Pearl Street that had been mounted in clear resin and polished in preparation for metallographic examination.

Figure 3.3.1 shows 10 full wall thickness slices.

Figure 3.3.1
Examples of full wall thickness metallographic macro sections cut from the 12-SG-N-FE piece of pipe.

A visual indication of the loss by corrosion can be obtained by comparison with the least corroded top end thickness of the third sample from the left.

Also, I examined on a metallurgical microscope the microstructures of samples prepared by Phil Cornish of Pearl Street.

I observed in the microstructures indications of spheroidisation of pearlite indicative of heat degradation of the steel.

3.4 *Mechanical Testing*

Mechanical test coupons were cut from 12-SG-S-F, which was the pipe immediately adjacent to 12-SG-N-FE in service.

Pearl Street carried out tensile testing and obtained the results shown in table 3.4.1.

Table 3.4.1
Tensile test results.

Pipe Section Identification	Specimen Identification	Specimen Dimensions (mm)		Yield Stress (Y.S.)	Ultimate Tensile Strength (U.T.S.)	% Elongation
		Width	Thickness	(MPa)	(MPa)	(in 50.8 mm)
12-SG-S-F Fractured end	Longitudinal 1	37.95	5.31	419	547	38
"	Longitudinal 2	38.04	5.12	395	532	35
"	Longitudinal 3	37.99	5.68	388	521	37

The API 5LX60 requirements are;

Minimum yield strength = 414 MPa

Minimum tensile strength = 517 MPa

Minimum required elongation is calculated from;

$$e = 1{,}944 \frac{A^{0.2}}{U^{0.9}}$$

where

e = minimum elongation in 2 in. (50.8 mm) in percent rounded to the nearest percent.

A = applicable tensile test specimen area, as follows:

a. For both sizes of round bar specimens, 0.20 in.^{2} (130 mm^2);

b. For full section specimens, the smaller of (i) 0.75 in.^{2} (485 mm^2) and (ii) the cross-sectional area of the test specimen, calculated using the specified outside diameter of the pipe and the specified wall thickness of the pipe, rounded to the nearest 0.01 in.^{2} (10 mm^2); and

c. For strip specimens, the smaller of (i) 0.75 in.^{2} (485 mm^2) and (ii) the cross-sectional area of the test specimen, calculated using the specified width of the test specimen and the specified wall thickness of the pipe, rounded to the nearest 0.01 in.^{2} (10 mm^2).

U = specified minimum ultimate tensile strength in psi (MPa).

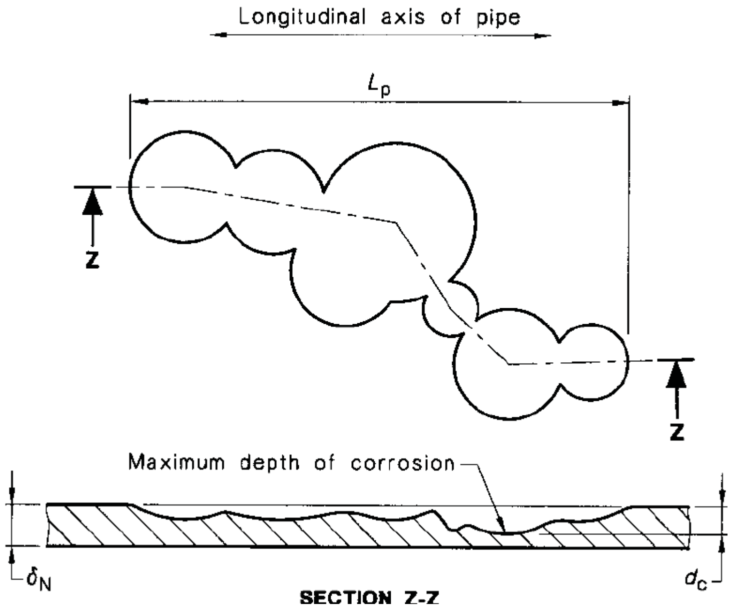
The minimum required elongation therefore is 24%.

4. Calculations to AS2885.3

4.1 MAOP with Corrosion Present

AS2885.3 allows corroded pipe to remain in service without repairs, provided that the maximum depth of corrosion does not exceed 80% of the nominal wall thickness and the maximum allowable operating pressure (MAOP) is adjusted by the method given in Appendix D of the standard. An extract of the method is given as Appendix I of this report.

Figure 4.1.1
Length and depth of corrosion from AS2885.3 figure D2.



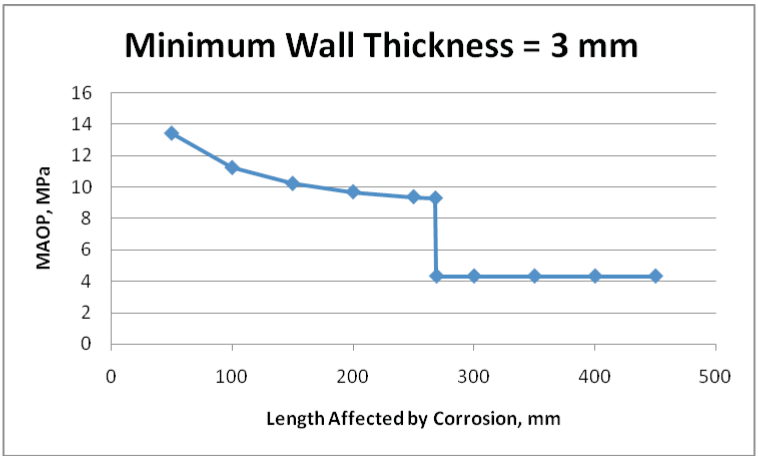
The length of corrosion (L_p) therefore refers to the projected length onto the longitudinal axis of the pipe.

4.2 *MAOP of the 12” Sales Gas Line*

I calculated the MAOP for the gas line using the equations of Appendix I, assuming various lengths affected by corrosion and assuming various maximum depths of corrosion.

Figure 4.2.1 shows a graph of corroded length against MAOP for an assumed minimum nominal wall thickness of 3 mm. The minimum nominal wall thickness is the nominal wall thickness of new pipe minus the maximum depth of corrosion.

Figure 4.2.1
MAOP for 3 mm minimum nominal wall thickness and various corroded lengths of 12” Sales Gas line.

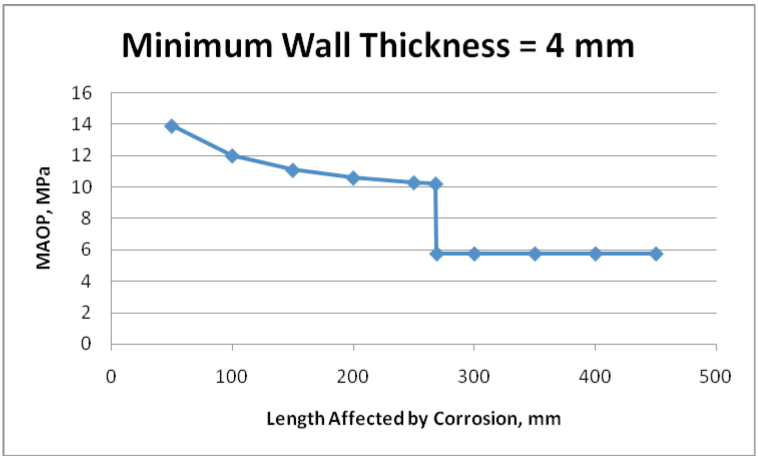


The MAOP can be seen to drop abruptly at a corrosion affected length of approximately 270 mm. The reason for this is that between a corroded length of 268 mm and 269 mm, the value of K_C reaches 4 (calculated from equation D3, Appendix I). When $K_C > 4$ the MAOP is no longer calculated from equation D4 but is calculated from equation D5. Equation D5 gives a constant MAOP value for a fixed maximum depth of corrosion, regardless of the length of pipe affected by corrosion.

Similary, a series of MAOP values were calculated for a minimum nominal wall thickness of 4 mm.

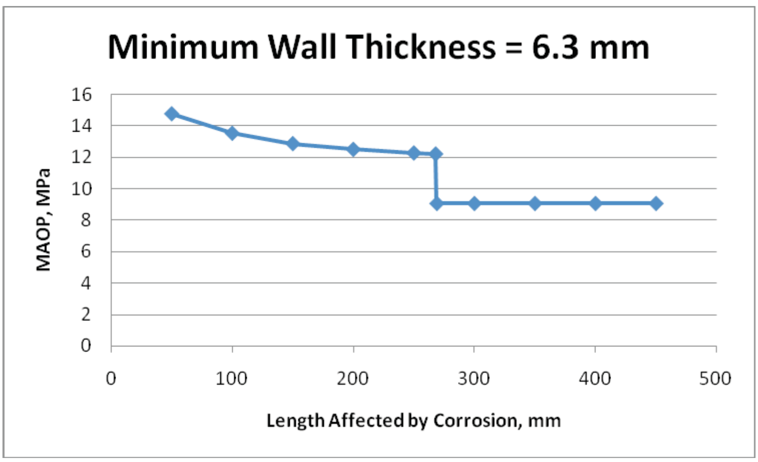
A graph of the results for 4 mm wall thickness is given as figure 4.2.2.

Figure 4.2.2
MAOP for 4 mm minimum nominal wall thickness and various corroded lengths of 12" Sales Gas line.



The limiting case for an allowable operating pressure of 9.168 MPa, reported to have been current at the time of the burst, is given by a minimum nominal wall thickness of 6.3 mm.

Figure 4.2.3
MAOP for 6.3 mm minimum nominal wall thickness and various corroded lengths of 12" Sales Gas line.



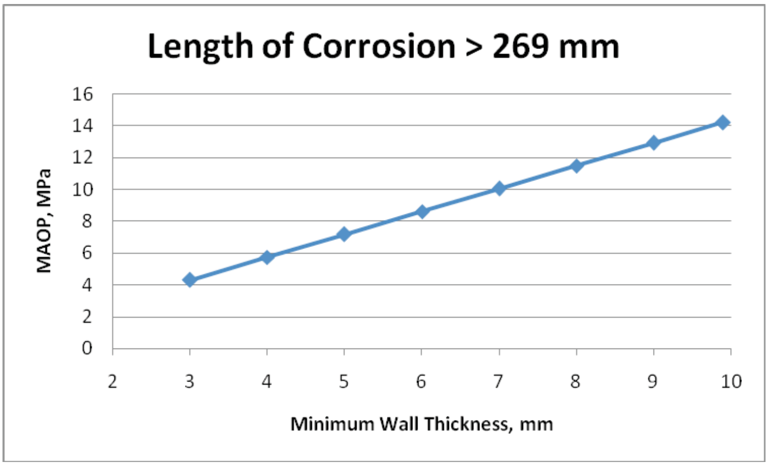
For cases where the minimum nominal wall thickness is greater than 6.3 mm, the MAOP exceeds the 9.168 MPa operating pressure current at the time of the explosion, regardless of the length of pipe affected by corrosion.

Between 6.3 mm and 9.9 mm minimum nominal wall thickness, the MAOP must be reduced to less than the original design value of 14.5 MPa.

When the projected length of corrosion exceeds 269 mm, the MAOP is determined by equation D5.

Figure 4.2.4 shows the various maximum allowable operating pressures for a range of minimum nominal wall thicknesses.

Figure 4.2.4
12" Sales Gas line MAOP for projected lengths of corrosion greater than 269 mm and various minimum nominal wall thickness.



5. Discussion and options

5.1 *Material*

The tensile strength of the samples of steel taken from the 12" Sales Gas line complied with the API 5LX60 minimum requirements. However, two of the three specimens shown in table 3.4.1 did not comply with the API 5LX60 minimum yield strength requirements.

The results may not represent the original material because it is possible that the yield strength had been affected by the fire which followed the pipe burst.

The elongation values all exceeded the API 5LX60 requirement.

5.2 *Corrosion & Operating Pressure*

It was clear from visual examinations and from thickness measurements that the corrosion on the 12" Sales Gas line was several times greater than a projected length of 269 mm. This being the case, AS2885.3 requires the MAOP to be reduced from the design value of 14.5 MPa and to be determined by equation D5.

Figure 4.2.4 shows the AS2885.3 MAOP requirements for the corroded 12" Sales Gas line.

The exact value of the minimum wall thickness prior to bursting could not be ascertained from the laboratory measurements because the fracture most likely would have passed through the thinnest region and that region also was subjected to thinning by plastic flow.

Due to probe diameter restrictions, all of the thickness mapping results obtained by Applus RTD were beyond the zones of significant plastic flow due to necking.

Two regions of mapping gave average thickness values in the range 3.0 mm to 4.0 mm. Therefore, the minimum pipe wall thickness is likely to have been less than 3.0 mm. The MAOP for a minimum nominal wall thickness of 3.0 mm is 4.31 MPa and 5.75 MPa for 4.0 mm minimum nominal wall thickness. The reported operating pressure at the time of bursting was reported to have been 9.168 MPa.

Given the reduced wall thickness, the gas line was not being operated in compliance with AS 2885.3.

6. Conclusions

i) The section of 12” Sales Gas line marked as 12-SG-N-FE with reduced wall thickness due to corrosion was being operated at a higher pressure that the maximum allowable operating pressure calculated in accordance with AS 2885.3. Therefore the gas line was not being operated in compliance with AS 2885.3.

ii) Two of the three specimens of 12” Sales Gas line subjected to tensile testing failed to comply with the minimum yield strength requirements of API 5LX60.

iii) The elongation values exceeded the API 5LX60 requirement.

iv) The microstructure of the steel in the burst region of 12” Sales Gas line showed evidence of deterioration by partial spheroidisation of pearlite.

v) The internal and external surfaces of the piece of 12” Sales Gas line that had been unwrapped by rupturing contained oxidation colouring indicative of being exposed to high temperatures subsequent to rupturing.

APPENDIX I

Calculation of MAOP of Corroded Pipe - Appendix D of AS2885.3

D3.2.3 *Review of corrosion parameter*

The procedure is as follows:

(a) *Step 1—Depth of corrosion* Measure the depth of corrosion (d_c) and express it as a ratio of the nominal wall thickness (δ_N) for the pipe. Evaluate this ratio as follows:

   (i) Where d_c/δ_N is equal to or less than 0.1, the MAOP (p_o) need not be reduced.

   (ii) Where d_c/δ_N is equal to or greater than 0.8, the corroded pipe shall be repaired.

   (iii) Where d_c/δ_N is greater than 0.1 but less than 0.8, proceed to Step 2.

(b) *Step 2—Length of corrosion* Measure the projected length of corrosion (L_p).

(c) *Step 3—Constant K_f* Calculate the value of the constant K_f from the following:

   (i) Where d_c/δ_N is less than or equal to 0.18, the value of the constant K_f is 4.

   (ii) Where d_c/δ_N is greater than 0.18, the value of the constant K_f shall be determined from Figure B3 or calculated from the following equation:

$$K_f = \left\{ \left[\frac{d_c/\delta_N}{(1.1 d_c/\delta_N) - 0.15} \right]^2 - 1 \right\}^{1/2} \qquad \text{. . . D1}$$

(d) *Step 4—Critical length of corrosion* Calculate the value of the critical length (L_c) from the following equation:

$$L_c = 1.12 K_f \ (D\delta_N)^{1/2} \qquad \text{. . . D2}$$

(e) *Step 5—Evaluation of the MAOP of corroded pipe* Evaluate the MAOP of corroded pipe as follows:

   (i) Where the critical length (L_c) is greater than the projected length (L_p), the MAOP (p_o) need not be reduced.

   (ii) Where the critical length is less than or equal to the projected length, the value of the constant K_c shall be calculated and compared with 4 and a new MAOP (p_c) calculated.

(f) *Step 6—Constant Kc* Calculate the value of the constant K_c from the following equation:

$$K_c = 0.893 L_p (D\delta_N)^{-1/2} \qquad \text{. . . D3}$$

(g) *Step 7—Value of Kc less than or equal to 4* Where the value of the constant K_c is less than or equal to 4, the new MAOP (p_c) shall be determined from Figure B4 or calculated from the following equation:

$$p_c = 1.1 p_o \left(\frac{1 - 2d_c/3\delta_N}{1 - 2d_c/[3\delta_N (K_c^2 + 1)^{1/2}]} \right) \qquad \text{. . . D4}$$

(h) *Step 8—Value of Kc greater than 4* Where the value of the constant K_c is greater than 4, the new MAOP (p_c) shall be determined from Figure D5 or calculated from the following equation:

$$p_c = 1.1 p_o (1 - d_c/\delta_N) \qquad \text{. . . D5}$$

Annex 4:
The Martin corrosion report

Corrosion Report

Rupture of 12” Sales Gas Pipeline Varanus Island

Document number: 215.002d

Client: Department of Mines and Petroleum WA

Date: 6 May 2009

Report by: Brian Martin & Associates Pty Ltd, Corrosion Engineers

Unit 8C, 22 Ross Street, Wollstonecraft, NSW 2065, Australia

Brian A Martin Signed Dated 06 / 05 / 2009	BSc (Applied Chemistry - NSW) MSc (Corrosion Science & Engineering – London) Registered Chartered Professional Engineer Fellow Institution of Engineers, Australia Fellow Institute of Corrosion, United Kingdom NACE Accredited Corrosion Specialist, USA Australasian Corrosion Association Corrosion Medal Australasian Corrosion Association Hon. Life Member

1. Executive summary

1.1 AEL inspection requirements

The Corrosion Risk Assessment and Inspection Scheme indicates that the pipeline in the immediate vicinity of Varanus Island requires a rigorous corrosion risk assessment, that the coastal section is more at risk of external failure than any other part of the pipeline, and that the most serious risk to the continuing integrity of the pipeline is where coating has disbonded. This level of risk assessment does not appear to have been carried out.

Statutory Inspection Manual requirements refer to offshore inspection requirements from VI to KP0 and onshore inspection requirements from KP0 to CS1. It does not recognise the beach crossing on VI as requiring onshore inspection requirements. The VI beach crossing has not received the inspections required by the Onshore Pipeline Inspection Manual.

1.2 *Applicable standards*

The CP testing procedure does not allow for measurement errors due to voltage gradients in the sandy backfill which, in accordance with AS2832.1, is required. As a result the measurements may indicate protection when the pipeline is not protected.

The CP protection criterion does not allow for the pipeline operating at the elevated temperature of 66˚C. The measurements may indicate protection at 25˚C (if they were compensated for voltage gradient errors) but may not provide protection at 66˚C.

1.3 *Inspections carried out*

Only one Shallow Water & Onshore Pipeline Inspection Report and five Pipeline General Inspection Reports have been received for input to this report. This does not comply with the Onshore Pipeline Inspection Manual requirement for annual reports.

The Shallow Water & Onshore Pipeline Inspection Report indicates areas of damaged coating and corrosion but anomalies were not recorded. This does not comply with the Onshore Pipeline Inspection Manual requires that any coating damage and any corrosion requires anomaly reports which then lead to investigation.

1.4 *Quality of reports*

The inspection reports are inadequate and do not comply with the AEL Onshore Pipeline Inspection Manual requirements.

The Review of Apache Pipelines by QCL – February 2004 is a competent report that raises the corrosion protection issues at the shore crossing.

The Lloyds Register reports raise some critical questions that relate to corrosion protection issues at the shore crossing, but sees “no impediment to continued safe operation” in spite of the questions.

The rest of the reports ignore critical information relating to corrosion protection at the VI shore crossing, and the summary when given contains unsupported conclusions that the shore crossing is not at risk.

1.5 *AEL response to reports*

AEL appears to have commenced annual monitoring of the CP potential at the isolation flange in 2006. However measuring the potential at the flange may not indicate the protection status of the pipeline. A full evaluation of the risk should have indicated this.

1.6 *Adequacy of cathodic protection*

The CP design was not adequate and the monitoring was not adequate.

1.7 *Likely cause of corrosion*

The primary cause of the corrosion failure was a lack of coating adhesion, most likely when the coating was applied or early in the life of the pipeline. In any case the cathodic protection design was inadequate to protect exposed steel of the pipe in the tidal sandy environment at the elevated temperature of the pipe.

1.8 *What would have mitigated the corrosion*

- The rupture would have been prevented by the proper repair of the coating in the beach area where the pipeline is subject to alternate immersion and non-immersion in sea water within the sandy environment.
- If the CP had been monitored at the beach crossing in accordance with AS2832.1:2004 the lack of protection should have raised an anomaly report and an investigation should have been undertaken which should have revealed the corrosion in time for mitigative action.

The requirement for this mitigation should have been revealed in the following reports:

- If the warnings contained in the 1998 AEL Corrosion Risk Assessment and Inspection Scheme Report were considered and addressed, and an intelligent pig run was carried out over the shore crossings.
- If the issues raised about the VI shore crossing in the 2004 QCL Review of Apache Pipelines was addressed and appropriate inspections undertaken.
- If the coating damage observed in the 2005 Shallow Water & Onshore Pipeline Inspection Report had lead to an anomaly report. The coating damage was also obvious by a simple visual inspection which was a part of the annual inspection requirement.
- If the questions raised in the 2006 - 2007 Lloyds Register Reports were fully addressed appropriate inspections would have been carried out.

Table of contents

2. Introduction

Varanus Island is used by Apache Energy Limited (AEL) as an oil and gas gathering and processing hub off the northwest coast of Western Australia. A portion of the sales gas is exported to the mainland via a 12" diameter Sales Gas Pipeline. On 3 June 2008 the pipeline ruptured at the beach crossing of Varanus Island.

The Department of Mines and Petroleum (previously the Department of Industry and Resources (DoIR)) is investigating the cause of the rupture and had engaged the National Offshore Petroleum Safety Authority (NOPSA) to provide technical support. They further engaged Brian Martin & Associates to provide specialist corrosion support. During the week of 4 to 8 August 2008 Brian Martin attended the offices of DoIR and NOPSA to review documentation, and also attended the offices of Pearlstreet to view pipe samples taken from Varanus Island after the rupture. Further documentation has since been forwarded to Brian Martin & Associates to include in the review.

Brian Martin & Associates were engaged to review documentation and prepare a report on:

- Adequacy of pipeline inspections
- Quality of reports
- Adequacy of AEL response to the reports
- Adequacy of cathodic protection systems
- Likely cause of corrosion
- Measures that would have mitigated the corrosion

The 12" Sales Gas Pipeline was installed in 1992, has a pipe wall thickness of 11.1 mm, is cathodically protected with bracelet anodes, and has a coating of 4.0 mm of asphalt enamel with 25 mm of concrete weight coat. The gas inlet temperature is 66˚C. (Reference AEL Pipeline Management Plan: Apache Pipelines Data Tables, Drawing SP-20-DL-001 and Drawing SP-14-DL-002.)

3. Adequacy of inspections

3.1 AEL Inspection Requirements

3.1.1. Statutory Inspection Manual

The Statutory Inspection Manual HE-00-MF-001 was issued in 1992 to cover "the policies and procedures for Statutory Inspections and Testing of the Apache Energy Ltd Offshore and Onshore Petroleum Handling Facilities. The mandatory procedures and required minimum inspection and/or testing frequency is shown for each category of equipment or system."

In Section II it requires that the Sales Gas Line be inspected:

a) Offshore: Annual inspection by ROV and cathodic protection survey every five years.

b) Onshore: Annual inspection of external / cathodic protection.

In Appendix Section II B the detailed requirements for the Sales Gas Line are:

- Varanus to KP0: Offshore inspection requirements.
- KP-0 to CS.1: Onshore inspection requirements.

3.1.2. Onshore Pipeline Inspection Manual

The rupture site may be regarded as being an onshore pipeline or an offshore pipeline. However the AEL Onshore Pipeline Inspection Manual OP-14-MG-001 issued in June 1997, with Revision 4 issued for use on 22 March 2006 says that it "covers the inspection of all the onshore sections of these pipelines, defined as that part of the pipeline between the landfall to the pipeline termination or pig launcher/receiver."

The Onshore Pipeline Inspection Manual requirements include:

a) An annual inspection is carried out until a risk assessment indicates that another inspection interval is more appropriate. The inspection would typically include:

    i. Topographical survey in surf zone / beach area to confirm depth of cover.

    ii. Visual inspection of unburied pipework to determine the condition of the coating, general corrosion and physical damage.

    iii. Cathodic protection (CP) survey.

b) Anomaly reports for all conditions outside the acceptance criteria. The acceptance criteria include:
   i. No coating damage.
   ii. No corrosion.
   iii. CP potentials outside of the range -850mV to -1200mV Cu/CuSO4.
c) When an anomaly is identified corrective action shall be initiated immediately.

3.1.3. Underwater Inspection Manual

The AEL Underwater Inspection Manual AE-00-MG-005 Rev 4 was issued for use in August 2005 and supersedes previous documents yet to be viewed. It requires that the following surveys be undertaken:

a) A Level 1 survey shall be carried out at least every 3 years. This is a side scan sonar survey.
b) A Level 2 survey shall be carried out at least every 3 years. This is a general visual inspection (GVI) and CP survey. The GVI scope includes:
   i. Determination of scour under and on the side of the pipeline
   ii. Extent and location of coating damage
   iii. Extent and location of pipeline damage
   iv. Pipeline burial depth.
c) A Level 3 survey shall be carried out following the discovery of suspect defect areas on the mainline as soon as possible after the defect has been found. It is a targeted visual inspection of the defect.
d) Level 4 surveys shall be carried out at the earliest opportunity to establish the precise characteristics of defects and any other suspect areas and to carry out remedial actions. Intelligent pig surveys shall be carried out at an interval not exceeding 5 years where there has been pipe wall metal loss.

3.1.4. Corrosion Risk Assessment and Inspection Scheme

The AEL LTS, Sinbad, Campbell and CS1 Corrosion Risk Assessment and Inspection Scheme HE-00-MN-003 revision 1 was issued in September 1998. Section 7.5 contains a corrosion risk assessment for the Sales Gas Pipeline from LTS to CS1 indicating the following:

a) 'The pipeline contains high pressure hydrocarbon gas … a failure in the immediate vicinity of Varanus Island or the mainland could endanger life, therefore … (it warrants) a rigorous and detailed assessment by well defined deterministic or probabilistic method concentrating on the probability of failure or the time to failure.'

b) 'A detailed design review of the (offshore) CP system is beyond the scope of this report ... The onshore section, particularly in the coastal mangrove areas, is less certain. Variation in local soil conditions means that the current requirement for full protection varies considerably. The location and conditions mean that close interval potential surveys are difficult, and so detailed checks for adequate potential in all areas are not currently performed ... The combination of warmer conditions, biological activity and tidal effects mean that the coastal section is more at risk of external failure than any other part of the pipeline. Therefore it is important that cathodic protection surveys be carried out."

c) 'The requirement for intelligent pigging on this line is dictated by the external corrosion hazard, particularly in the coastal mangrove section of the line. The most serious risk to the continuing integrity of the pipeline is where coating has disbonded, creating a region of wet, bare metal shielded from cathodic protection current. Corrosion may occur despite adequate cathodic protection potentials ... The economic and safety consequences of a failure of the Sales Gas pipeline, coupled with the difficulty of surveying the coastal section, and the risk of a coating disbondment failure mean that regular intelligent pigging of the line is justified. To save cost, this survey may be concentrated on the coastal and onshore sections of line. The period is arbitrary - a figure of 5 years is suggested.'

3.1.5. Review

The Statutory Inspection Manual requirements refer to offshore inspection requirements from VI to KP0 and onshore inspection requirements from KP0 to CS1. It does not recognise the beach crossing on VI as requiring onshore inspection requirements. This is a significant error.

The general requirements of both the Onshore Inspection Manual and the Underwater Inspection Manual are in keeping with good industry practice. The Onshore Inspection Manual is more appropriate for the beach zone where the rupture occurred as this area is not accessible by boat or ROV, and most of the Underwater Inspection Manual inspection requirements require boat and ROV access. The allowable onshore CP potential range does not specify that the criteria are only applicable if there 'is not a significant voltage gradient in the electrolyte between the structure and the reference electrode.' in accordance with AS2832.1. If there is such a voltage gradient then alternative test methods have to be used. This is a significant error.

The Corrosion Risk Assessment and Inspection Scheme indicates that:

a) The corrosion risk to the pipeline in the immediate vicinity of Varanus Island requires a rigorous corrosion risk assessment. (However this does not appear to have been carried out.)

b) The coastal section is more at risk of external failure than any other part of the pipeline, however adequate testing is not currently performed in these areas. (It refers to the mainland coastal section in particular, but the VI coastal area is at a similar risk due to temperature and tidal effects.)

c) The most serious risk to the continuing integrity of the pipeline is where coating has disbonded. Corrosion may occur despite adequate CP potentials therefore regular intelligent pigging of the line should be carried out. (This particularly applies to the tidal zones at VI and the mainland, but such pigging does not appear to have been carried out.)

3.2 *Applicable Standards*

3.2.1. AS2885

Both TPL/8, the Licence for the offshore section of the 12” Sales Gas Pipeline, and PL12: Variation No 1/91-2, the Licence for the Varanus Island onshore section of the pipeline, call up compliance with the Australian Standard AS2885 ‘Pipelines – Gas and liquid petroleum’. AS2885.3 – 2001 ‘Operation and maintenance’ is the standard that covers ongoing pipeline integrity inspections. This standard is risk based and does not provide proscriptive requirements for inspection intervals. The relevant requirements are:

a) The frequency of inspection and assessment should be documented and approved and based on the past reliability of the pipeline, historical records, current knowledge of its condition, the rate of deterioration (both internal and external corrosion, coating degradation and the like), and statutory requirements.

b) Above ground pipelines shall be inspected for evidence of corrosion or damage to or deterioration of any anti-corrosion coatings at intervals as specified in the safety and operating plan, and the rate of corrosion shall be assessed. Where the rate of corrosion will reduce design life, remedial action shall be taken.

c) Whenever any part of a buried or submerged anti-corrosion coated pipeline is exposed, it shall be inspected for corrosion and evidence of damage to, or deterioration of, any anti-corrosion coatings.

d) Where corrosion is detected, it shall be investigated to determine its nature, extent, depth and cause. The corrosion shall be evaluated and ... a new MAOP shall be established or the corroded portion of the pipeline shall be repaired or replaced.

e) Cathodic protection shall be monitored in accordance with AS2832.1. It requires that:

   i. CP surveys for onshore pipelines in rural areas be carried out at not more than 12 monthly intervals.

   ii. The CP potential be between -850mV and -1200mV Cu/CuSO4 for ambient temperatures and if there is no significant voltage gradient in the electrolyte between the structure and the reference electrode. Higher temperatures require more negative potentials. The standard provides methods for determining the presence of significant voltage gradients and in general are significant for onshore pipelines.

3.2.2. Review

Insufficient inspection history has been provided to enable a quantification of appropriate inspection and assessment frequency. However the inspection frequency presented in the AEL Inspection Manuals would be appropriate.

The CP testing procedure does not allow for voltage gradients in the electrolyte which, with the sand environment, could be substantial as indicated in Section 7.1.

This can result in the pipeline not being protected even though the measured potentials may indicate protection.

The CP criterion does not allow for the pipeline operating at the elevated temperature of 66˚C. This will require a more negative potential to provide protection. The magnitude of the variation needs to be determined by AEL for their circumstances.

3.3 *Inspections Carried Out*

3.3.1. Inspections

Of the information provided and received, only one inspection report applies to the shore crossing prior to 2006. This is consistent with:

i. The Review of Apache Pipelines, February 2004 by QCL which says in Section 2.2:

   'At present the shore zones do not seem to be included in either of the (onshore or offshore) standard inspection workscopes.'

ii The AEL document Statutory Inspection Manual, 1992 which does not recognise the onshore inspection requirements at VI for the 12" Sales Gas Line.

iii The East Spar - Audit Apache Share Facilities, 8 September 1995 which says under Sales Gas Pipeline (offshore):

   "Regular CP surveys, although a statutory requirement, have never been performed."

The inspection reports received are:

a) 2004 Shallow Water & Onshore Pipeline Inspection

The Varanus Island Ultra Shallow Water and Onshore Pipeline Inspection Report dated May 2005 reports on the inspection of the 12" Sales Gas Pipeline between KP 68.243 to 69.703. The Condition Summary is presented as:

Subsea – There was one anomalous area of damaged weight coating at KP69.703.

Onshore – Whilst there were no anomalies recorded during the onshore survey, there were some areas of damage and corrosion noted.

The detailed corrosion related report is presented as:

Subsea – Missing weight coat over a 1m section of pipeline.

The two recorded anodes appeared active and secure.

No CP readings were taken on the 12" Sales Gas Export Line during the course of the survey.

Onshore – West of Cyclone Protection Enclosure:

5000mm corroded mesh appearing under weight coat

5000mm corroded mesh appearing under weight coat

300 x 500 corrosion visible under wrap

East of Cyclone Protection Enclosure:

Missing weight coat 2m long

Minor crack in weight coat

b) 2007 Pipeline General Inspection

The Pipeline General Inspection Report contains the following corrosion related information:

Cathodic protection	-867mV
Onshore/Offshore Tie-in	Not seen completely submerged and buried
Isolation Flange	Not seen completely submerged and buried
Pipeline Coating	Not seen completely buried and what is buried is weight coated

c) Varanus Island Offshore Pipelines – Onshore Section CP Survey
August 2004

The report R115201A by Auscor as received does not present any cathodic protection survey results but it does indicate that the 12" Sales Gas Line has had magnesium anodes installed adjacent to the isolation flange to protect the onshore section of the pipeline and to offset the interference effects from the CP systems on the storage tanks.

d) Varanus Island Offshore Pipework Monitoring Reports by Auscor

Three one page reports were received that indicate the potentials of the Sales Gas Line at VI with the CP systems energised. The potentials recorded are:

- 18 June 2006 -805mV Cu/CuSO4
- August 2007 -917mV Cu/CuSO4
- 3 May 2008 -1069mV Cu/CuSO4

3.3.2. Review

a) The limited number of inspection reports received for the 15 years of operation of the pipeline do not comply with the Onshore Pipeline Inspection Manual requirement for annual reports.

b) A topographical survey was not carried out to confirm depth of cover as is required by the Onshore Pipeline Inspection Manual for beach/shore crossings.

c) There are areas of damage and corrosion noted on the onshore section but anomalies were not recorded. (The Onshore Pipeline Inspection Manual requires that any coating damage and any corrosion require anomaly reports.)

d) The report indicates that there was a 2m section of missing weight coat. Photos taken subsequent to the rupture indicate that as well as the weight coat the anti-corrosion asphalt enamel coating was probably missing as well.

The photograph on the right is from Photograph A52741 and shows the end of the asphalt enamel. The asphalt enamel is to the right and the bare pipe (or primer only coated pipe) to the left. The photograph on the left is from Photograph A52742 and shows the end of the asphalt enamel on the close side of the stainless steel strap, and how the lack of asphalt enamel extends to the remote concrete weight coat near the water.

e) The 2007 Pipeline General Inspection Report indicates that the onshore/offshore tie-in, the isolation flange and the pipeline coating were not seen as they were completely submerged and buried. From the left photograph shown above it is apparent that on occasions at low tide an area of the Sales Gas Pipeline is visible near the shore crossing. Observations should be made when the pipeline is visible.

f) The 2007 Pipeline General Inspection report indicates that the isolation flange is at the beach/shore crossing area as it is "completely submerged and buried", whereas the adjacent 12" Campbell/Sinbad isolation joint at the same time is "okay" which we assume means it is above ground and probably at the plant outlet flange. However the Varanus Island Offshore Pipelines Onshore Section CP Survey Report of August 2004 says that magnesium anodes were installed near the isolation flange to supplement the cathodic protection. This indicates that the isolation flange is probably at the plant outlet flange. If the isolation flange is at the plant outlet flange then the offshore bracelet anodes will affect the protection at the beach crossing. If the isolation flange is at the beach crossing the onshore anodes will have the only protective affect on the pipeline.

g) The CP potentials reported, of between -805 and -1069 mV Cu/CuSO4, would not protect the pipeline as detailed in Section 7.1 below.

h) The Auscor CP survey of August 2004 indicates that the CP systems on the storage tanks causes CP interference to the 12” SGL. This interference makes the CP potential on the pipeline less negative and thus can increase the rate of corrosion on the pipeline if not adequately mitigated.

4. Quality of reports

4.1 *Corrosion Risk Assessment and Inspection Scheme by AEL – September 1998*

The inhouse report, HE-00-MN-003 revision 1, presents a corrosion risk assessment and inspection requirement. While it does identify the high corrosion risk in tidal areas, the risk due to disbonded coating preventing CP current from reaching the steel surface, and the difficulty in carrying out meaningful CP surveys in tidal areas, it only addresses these risks for the mainland onshore tidal area recommending five yearly intelligent pigging. It makes no recommendation for the VI tidal area implying that it would be too expensive: “To save cost, this survey may be concentrated on the coastal and onshore sections of line.”

4.2 *Review of Apache Pipelines by QCL – February 2004*

The QCL report, 5226/2942, presents a good critical review of AEL inspections and indicates that:

a) In Table 11.1 the Review indicates that ‘No (external corrosion) inspection data is available for the pipeline shore zone.’ and that the risk probability is medium, the consequence is critical and the risk level is high.

b) In Section 2.2 it says that ‘At present the shore zones do not seem to be included in either of the standard (onshore or underwater) inspection workscopes.’ It recommends that “the inspection procedures for offshore and onshore inspections be modified to ensure that the offshore section is inspected during HAT and the onshore section is inspected during LAT, ensuring sufficient overlap.”

4.3 *Shallow Water & Onshore Pipeline Inspection – May 2005*

The inspection report is unsatisfactory and does not comply with the AEL inspection annual requirements:

a) It did not present a topographical survey of the pipeline in the beach/shore zone.

b) Coating damage and corrosion anomalies were observed but not reported as anomalies.

c) No CP readings were taken.

d) A section of missing weight coating was noted, however it was most likely missing anti-corrosion coat that was missing. (See Item 3.3.2e above.)

4.4 *Annual Summary Report – January 2006*

The report repeated the observations of the Shallow Water & Onshore Pipeline Report. However while the Shallow Water & Offshore Pipeline report indicated that no cathodic protection readings were taken, the annual summary report indicated that 'the CP reading taken suggests that the pipeline is adequately protected.'

4.5 *Lloyds Validation Reports – May 2006 to April 2007*

Lloyds Register produced five validation reports between May 2006 and April 2007. While the PL12 Validation Summary Report (AEL document AE-14-RL-003 Rev A) concluded that 'No impediment to continued safe operations with PL12 requirements was identified.', a number of issues was raised:

a) The Integrity Audit Report 12 to 19 May 2006 S11 says 'Apache should ... ensure that examinations are carried out sufficiently frequently to identify ... which is likely to affect the ongoing safe operation of the whole facility and process.'

b) The Process Integrity Review Report 12 to 14 June 2006 Item 2.5.5 says 'Minimal risk facilities ... (are given a) general overview of facilities and equipment for gross oversight only ... (such facilities include) Corrosion Monitoring Systems (and) Cathodic Protection'

c) The Process Integrity Review Report 3 to 7 August 2006 Suggestion S16 says 'Apache should clearly define anomaly close-out requirements including who should receive and evaluate the data, what signatures are required at which stages and peer review requirements.'

d) The Process Integrity Review Report 28 September to 2 October 2006 Item 6.7 asks 'Are the limitations of the applied corrosion monitoring and inspection techniques known?'. The reply is "Limitations are documented in reference codes and standards know to the competent personnel involved with corrosion monitoring and inspection."

e) The Process Integrity Review Report 28 September to 2 October 2006 Item 6.7 asks 'Is it clear who should receive and evaluate this (integrity management) data.' The reply is 'It is not clear who should receive and evaluate specific data pertaining to integrity management, maintenance management and safety critical systems.'

4.6 *Review of Recommendations from 2004 Risk Assessments – April 2007*

The report by Moduspec reviews the QCL Review of Apache Pipelines.

The QCL Report indicates that:

- There is no inspection data for the VI shore zone.
- The VI shore zone does not appear to be included in either the onshore or offshore inspection procedures.

In summary the QCL Report rates the lack of inspection data as "High Risk" to pipeline integrity.

However the Moduspec Report does not mention the lack of inspection data and in Section 10.3 of the report it says that the shore zone of Varanus Island is deemed to be protected against external corrosion by the CP system.

4.7 *Sales Gas Pipelines - 5-Year Integrity Review – May 2007*

The report, AEL document SP-14-RL-067 revision 0, reviews all of the inspection reports and reviews relating to the Sales Gas Pipelines from 2000 to 2007. It concludes that 'there are no findings ... that provide any reason for any changes to the ongoing IMR activities that are not already being addressed'.

4.8 *Pipeline General Inspection VI 12" Sales Gas Line – August 2007*

The report is inadequate as indicated in Items 3.3.2e, 3.3.2f and 3.3.2g above.

4.9 *Varanus Island Offshore Pipework Monitoring Reports by Auscor*

There are three one page reports that just present the potential of the pipeline without further detail. They are dated 2006, 2007 and 2008.

4.10 *Varanus Island Offshore Pipelines – Onshore Section CP Survey August 2004*

The Auscor report by as received does not contain any CP protection status survey data.

4.11 *Summary*

The inspection reports are inadequate and do not comply with the AEL Onshore Pipeline Inspection Manual requirements.

The Review of Apache Pipelines by QCL – February 2004 is a competent report that places a 'high risk' to pipeline integrity at the shore crossing. However the review of this document by Moduspec ignores this concern.

The Lloyds Register reports raise some critical questions that relate to corrosion protection issues at the shore crossing, but sees 'no impediment to continued safe operation' in spite of the questions.

The Shallow Water & Offshore Pipeline Inspection Report 2005 indicated that no cathodic protection readings were taken, however the annual summary report indicated that 'the CP reading taken suggests that the pipeline is adequately protected.'

A number of reports ignore critical information relating to corrosion protection at the VI shore crossing, and the summary when given contains unsupported conclusions that the shore crossing is not at risk.

5. AEL response to reports

5.1 Reports Reviewed

The following reports were received that covered the area of the rupture up until 2005:

a) **February 2004 : Review of Apache Pipelines by QCL**

In Table 11.1 the Review indicates that 'No (external corrosion) inspection data is available for the pipeline shore zone.' and that the risk probability is medium, the consequence is critical and the risk level is high.

In Section 2.2 it says that 'At present the shore zones do not seem to be included in either of the standard (onshore or underwater) inspection workscopes.' It recommends that 'the inspection procedures for offshore and onshore inspections be modified to ensure that the offshore section is inspected during HAT and the onshore section is inspected during LAT, ensuring sufficient overlap.'

b) **May 2005 - Shallow Water & Onshore Pipeline Inspection**

Section 3.2.2 indicates the following:

Subsea – Missing weight coat over a 1m section of pipeline.

No CP readings were taken on the 12" Sales Gas Export Line during the course of the survey.

Onshore – West of Cyclone Protection Enclosure:

5000 mm corroded mesh appearing under weight coat

5000 mm corroded mesh appearing under weight coat
300 x 500 corrosion visible under wrap

East of Cyclone Protection

Enclosure:

Missing weight coat 2m long

Minor crack in weight coat

5.2 AEL Response

AEL appears to have commenced having the cathodic protection potential measured at the isolation flange annually. However measuring the potential at the flange may not indicate the protection status of the pipeline as indicated in Section 7.1 below. A full evaluation of the risk should have indicated this.

The Lloyds Register Process Integrity Review Report 28 September to 2 October 2006 Item 6.7 asks "Are the limitations of the applied corrosion monitoring and inspection techniques known?". The reply given is that ‘Limitations are documented in reference codes and standards know to the competent personnel involved with corrosion monitoring and inspection.’ The limitation of measuring potentials in the manner being used onsite is indicated in AS2832.1:2004, but was not acted on.

6. Adequacy of cathodic protection

The documents supplied are unclear as to what CP system was to protect the rupture area of the pipeline. Pipeline License TPL/8 and the 2007 General Pipeline Inspection of the 12” Sales Gas Pipeline indicate that there is an isolation flange at the beach crossing. In this case the pipeline at the rupture would not receive CP current from the offshore bracelet anodes.

If however the isolation joint was at the VI outlet valve, as is the case with the 12” Campbell/Sinbad Line and is implied from the Auscor Report from August 2004, then the rupture area would have received CP current from the bracelet anodes. The Auscor Report also indicates that magnesium anodes were installed and attached to the pipeline at the isolation flange to supplement the cathodic protection from the bracelet anodes and to mitigate the interference from the CP systems on the storage tanks. This seems the most likely scenario and is used in the following discussion.

The bracelet anodes, even with 12 magnesium anodes installed at the isolation flange, would not provide cathodic protection to the pipeline in the tidal area. The reason for this is detailed in Section 7.1 below. The CP monitor of measuring potentials without correction for electrolyte voltage gradient error would not ensure that the pipeline is protected.

The CP design was not adequate and the monitoring was not adequate.

7. Likely cause of corrosion

The corrosion protection system for the external surfaces of the pipeline has two major components; CP and coating.

7.1 Cathodic Protection

7.1.1 Tidal sand environment

The four CP potential readings measured at the isolation flange, documented in the test reports, varied between -805 and -1069 mV $Cu/CuSO_4$. However the pipeline appears to have been installed in a sand environment. The difficulty in obtaining CP in a sand environment is that when the sand is saturated with sea water is has a low resistivity and CP current flows readily. When the tide goes out, or when a wave retreats, the sea water rapidly drains from the sand due to its coarse particle size. This makes the sand much more resistive. Therefore much more negative CP potentials are required to provide CP. Such potentials are not available from the range of potentials measured above.

The photograph below is Photograph P1010253 and shows the sand environment at the rupture site.

To allow for the effect of environment resistivity on CP, CP standards require that the CP potential be measured with a technique that allows for this phenomenon. For example AS2885.3:2001 calls up the CP criteria in accordance with AS/NZS2832.1:2004 which, in Clause 2.2.2.1, says that the criteria apply providing that there is not a significant voltage gradient in the electrolyte between the structure and the reference electrode. Then in Appendices B and C it gives a number of ways of carrying out the measurement when the voltage gradient is significant. These alternative techniques do not appear to have been carried out on VI.

The following resistivities were measured on a beach in Perth. Whilst the resistivities on VI may be different, these values provide an insight into the magnitude of the changes that may be experienced in such environments:

- Sea water 0.22 Ωm
- Sand saturated with sea water 1.07 Ωm
- Wet sand immediately after draining 50.60 Ωm
- Sand wet so it just balls in the hand 81.30 Ωm
- Dry sand >2000.00 Ωm

Therefore wet drained sand can have about 50 times the resistivity of saturated sand. In other words the beach crossing pipe will require 50 times the cathodic protection driving voltage in drained sand than in immersed sand to provide the same current density.

For the sake of the calculation if we assume:

- The pipeline is bare for 4m of its length.
- It was buried with 500mm of cover.
- Its CP requirement is 20mA/m^2.

Then using Dwight's formula for calculating the resistance of a buried cylinder the resistance in 1 Ωm sand is 0.16 Ω, and in 50 Ωm sand is 8.14 Ω.

The current requirement is 75.41mA which using Ohms Law gives a driving voltage requirement of 12mV and 614mV respectively.

When there is no voltage gradient the CP criterion is -850mV Cu/CuSO4. However when the driving voltage requirements are included the protection criterion in 1 Ωm sand becomes -863mV and in 50 Ωm sand becomes -1464mV. This is significantly negative of the -805 to -1069 mV Cu/$CuSO_4$ potentials reported. Therefore the CP system would not have been effective on tidal sections of the beach crossing.

7.1.2. Effect of bracelet anodes

The most negative potential aluminium bracelet anodes have is about -1150mV Cu/$CuSO_4$. Magnesium has a potential of about -1500mV Cu/$CuSO_4$. However if magnesium anodes located onshore are connected to a long offshore pipeline protected with aluminium bracelet anodes, the magnesium will have little effect on the CP potential.

Because the magnesium is more negative than the aluminium it will corrode to provide protection to the large area of bare aluminium anode.

The magnesium has a lower surface area and is in an area of higher resistivity than the aluminium and therefore has a much higher resistance to earth. This results in the potential of the magnesium being far less negative than indicated by the -1500mV $Cu/CuSO_4$ value.

For the sake of the calculation if we assume:

- The bracelet anodes total 2000m of 0.3m diameter aluminium in 1 Ωm silt.
- There are 12 magnesium anodes of 0.1m diameter and 1.5m long in 100Ωm sandy soil.

The magnesium anodes would have a resistance to earth of 4.3Ω. A voltage difference between the magnesium and aluminium of 350mV (-1500 less -1150 mV) would result in a current of 81mA.

The aluminium would have a resistance to earth of 0.001Ω. The current of 81mA from the magnesium would affect its potential by less than a tenth of a millivolt. The potential from the magnesium would rapidly fall towards the potential of the aluminium with increasing distance from the magnesium. Pipe that is 26m from the magnesium anodes would have a potential of -1200mV instead of the -1500mV anticipated from magnesium. This is insufficient for protection as indicated above.

Therefore the magnesium anodes are unlikely to provide protection to the pipeline at the beach crossing.

7.2 *Coating*

For corrosion to occur the coating must have failed. Where the coating failed is obvious from the pipeline samples at Pearlstreet. The photograph below left shows the areas of substantial corrosion penetration where the coating failed, and the areas of zero corrosion where the coating remained intact. There was approximately 7m of the 12” Sales Gas Pipeline at Pearlstreet, most of which had areas of substantial corrosion penetration. The photograph below right shows the VI cut back end of the pipeline indicating that it is also uncoated and rusty. The adjacent 12” Campbell – Sinbad line can be seen as having intact coating, and the pipe samples at Pearlstreet indicated minimal corrosion compared with the 12” Sales Gas Line.

The Photographs in Section 3.3.2 above show corrosion coating failure of the 12” Sales Gas Pipeline near the beach crossing and intact coating on the 12” Campbell – Sinbad Line. It is evident that the coating on the 12” Sales Gas Line had failed on VI and that the coating on the adjacent 12” Campbell – Sinbad Line, which was constructed at the same time, was in a significantly better condition.

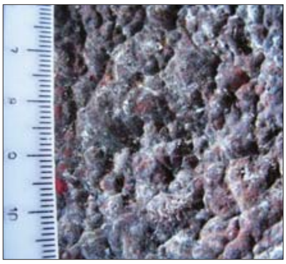
The question is whether the corrosion coating failed by loss of adhesion and was displaced from the pipe surface, or whether it failed by loss of adhesion but was still held in place by its own cohesive strength or the concrete weight coating. If the coating was displaced from the pipe surface then an appropriately designed CP system could provide protection in the wet sand drained of sea water. If however the coating lost adhesion but remained in place then CP current could not reach the steel surface due to shielding by the insulating coating. Corrosion could then proceed under the disbonded coating with the sea water moving up the crevice when the pipe was immersed. There is insufficient data available to determine which the situation was. However the corrosion depth map of the 12” Sales Gas Line and the 12” Campbell - Sinbad Line, which is to be prepared, may assist in determining the cause of the failure by showing whether there is a relation between corrosion penetration and tidal effects.

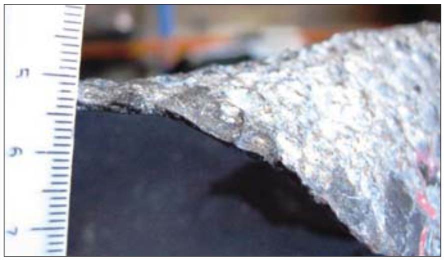
7.3 *Corrosion*

The following photographs taken at the Pearlstreet inspection indicate the severity of the corrosion:

The above photograph was taken near the rupture site on the beach side of the rupture. It shows the substantial corrosion that has occurred since the coating failure.

The two photographs below show the corrosion adjacent to the rupture edge with a mm ruler to show scale. The photograph on the right shows that the remaining wall thickness at the rupture was of the order of one or two mm at this location. That represents a corrosion penetration of approximately 10 mm since the coating failure.





A 10 mm corrosion penetration, if the coating failure occurred during construction, represents a rate of corrosion of 0.7 mm/year over the 15 years since construction. The typical maximum corrosion rates for steel subject to crevice corrosion are similar to the typical maximum corrosion rate for steel subject to intermittent immersion in sea water. That rate of corrosion is of the order of 0.5 mm/year, but at a temperature of 66˚C would be expected to be higher. Therefore it is likely that the coating failure was present at pipeline installation or very soon thereafter.

7.4 *Conclusion*

The primary cause of the corrosion failure was most probably due to a lack of coating adhesion when the coating was applied, or a loss of coating adhesion early in the life of the pipeline. If the lack of adhesion resulted in the coating being displaced from the pipeline, the cathodic protection design was inadequate to prevent the corrosion. If the lack of adhesion did not result in the coating being removed, cathodic protection would not be able to prevent corrosion occurring under the insulating layer of coating. In any case the cathodic protection design was inadequate to protect exposed steel of the pipe in the tidal sandy environment at the elevated temperature of the pipe.

8. What would have mitigated the corrosion

a) If the warnings contained in the 1998 AEL Corrosion Risk Assessment and Inspection Scheme Report were considered and addressed, and an intelligent pig run was carried out over the shore crossings, the corrosion would have been identified in time for mitigative action.

b) If the issues raised about the VI shore crossing in the 2004 QCL Review of Apache Pipelines was addressed and appropriate inspections undertaken, the corrosion would have been identified in time for mitigative action.

c) If the coating damage observed in the 2005 Shallow Water & Onshore Pipeline Inspection Report had lead to an anomaly report, as is required by the AEL Onshore Pipeline Inspection Manual, an investigation should have been undertaken which should have revealed the corrosion in time for mitigative action. This damage was also obvious to a simple visual inspection which was a part of the annual inspection requirement.

d) If the questions raised in the 2006 – 2007 Lloyds Register Reports were fully addressed appropriate inspections should have been carried out which should have identified the corrosion in time for mitigative action.

e) The corrosion would have been prevented by the proper repair of the coating in the beach area where the pipeline is subject to alternate immersion and non-immersion in sea water within the sandy environment.

f) If the CP had been monitored at the beach crossing in accordance with AS2832.1:2004 then the lack of protection should have raised an anomaly report, as is required by the AEL Onshore Pipeline Inspection Manual, and investigation should have been undertaken which should have revealed the corrosion in time for mitigative action.

Annex 5: The Gubner corrosion and CP report

Assessment of possible and likely scenarios for the corrosion that led to the rupture on the 12 inch Sales Gas Line on Varanus Island

Document number: FR-013-2009-D

Project Number: 013-2009

Client: Department of Mines and Petroleum WA

Date: 8 June 2009

Report by: Prof. Rolf Gubner, Western Australia Corrosion Research Group – Curtin University of Technology

1. Background

At the request of Kym Bills and David Agostini, the Western Australian Government Department of Mines and Petroleum contracted Prof. Rolf Gubner, Curtin University of Technology, Director of the Western Australian Corrosion Research Group on the 15th of May 2009 to conduct a assessment of possible and likely scenarios for the corrosion that led to the rupture on the 12 inch SGL on Varanus Island on June 3rd, 2008. All information related to the incident on Varanus Island has been made available by the Department of Mines and Petroleum.

Contents

2. Review of data available – knowledge gap analysis

A number of investigations into the incident have been performed by a several consultants and experts in the field. There is no doubt that the incident was caused by severe external corrosion of the 12" Sales Gas Pipeline, where a long section of the pipe thinned sufficiently not to withstand the operating pressure at the time of incident. The resulting fracture has most likely caused the gas escaping to ignite, resulting in a fire that directly impacted on the close by 12" Sindbad/Campbell gas pipeline (ca 226 mm distance between the pipes), which resulted in a series of further ruptures of other pipelines. The timeline of the incident and series of events has been well established and is not subject to further discussion in this report.

Little information is available about the corrosion protection system(s) used to protect the Varanus island facilities and pipelines. The pipeline overview below (Table 1 & 2) has been collected from different reports and archived correspondence between Apache Energy Limited and the WA Department. It can be noted that not a complete record could be provided for a single pipeline that details the measures against corrosion, such as coating system applied and cathodic protection system applied, etc.

To my knowledge, no efforts have been made to investigate the risk for interference between the multitude of pipelines and installed equipment on Varanus Island. In the area of the incident are 6 pipelines installed next to each other over a width less than 10 meters. The pipelines are crossing each other closer to the processing facility and the offshore section the sales gas line is crossed by two pipelines (at KP67.665 and KP66.17). AS 2885.1-2007, Appendix C Threat Identification, states that Threat Identification consists of all threats to the pipeline. External interference and corrosion are explicitly named. Any pipeline that follows AS 2832.1 (Cathodic Protection) needs to take into account the risk for stray current corrosion and interference from other steel structures in close proximity of the pipeline. Even leaving the standards to the side, the high risk of interference from nearby CP systems is mentioned in nearly every CP design book and books that deal with pipeline corrosion, e.g., Peabody's Control of Pipeline Corrosion, first published in 1967 by NACE International.

Table 1: Description of pipelines looking from the beach towards the gas plant (6 June 2008)

Pipe	Pipe details	Date installed	Surface/ buried at rupture site	Observations (by Rolf Gubner):
16" sales gas pipeline	75 mm Concrete weight coating 4 mm Asphalt enamel corrosion coating (sub-sea section),	1999, 20 year design life	Surface	Design: above ground Little details on actual CP design available. 6,000 mm distance to 6" Harriet Gas Pipeline
6" Harriet to Varanus Island gas line	Stabilisation by trenching and mattresses offshore, no concrete weight coating 4 mm fusion bond epoxy	1988/89 20 year design life	Buried	Design similar to 8" Wonnich lines, the corrosion protective coating is not adequate for buried structures. Epoxy coating is not stable against UV light. Little information on CP 950 mm distance to 30" Crude Oil Pipeline
30" crude oil export line	65 mm Concrete weight coating 4 mm fusion bonded epoxy coating	1986, 20 year design life	Surface/ partially buried	Little information on CP (design and insulation flanges) 1400 mm distance to 12" Sales gas Pipeline
12" sales Gas pipeline	25 mm concrete weight coating and 4.5 mm asphalt enamel (sub-sea section and shore crossing)	1992, 25 year design life	Only partially buried at shore crossing	Apache Drawing nr SP-20-DL-001, rev. 5 (07.09.07) states that the onshore section on Varanus Island has no CP. The same drawing states that for the on-shore section on Varanus Island the following coating system was applied: 2 pack epoxy zinc rich primer min DFT 70µm plus high pack polyamide epoxy min DFT 200µm plus Polyurethane min DFT 50µm A September 2007 Apache Onshore Pipeline Inspection workbook lists the onshore pipeline survey history for the 12 inch SGL since installed in 1993 (sic). This report indicates that that the onshore/offshore tie-in point, the isolation flange and the pipeline coating were not seen as they were completely buried (at the beach crossing); and that the buried section was weight-coated, making the anti-corrosion coating inaccessible for visual assessment. TPL/8 indicates an isolation flange at the beach crossing. The Auscor Report also indicates that magnesium anodes were installed and attached to the pipeline at the isolation flange to supplement the cathodic protection from the bracelet anodes and to mitigate the interference from the CP systems on the storage tanks. All inspection reports assume that the onshore section is protected by CP, the drawing contradicts this, as does the work book. 226 mm distance to 12" Sinbad/ Campbell Gas pipeline

Pipe	Pipe details	Date installed	Surface/ buried at rupture site	Observations (by Rolf Gubner):
Campbell/ Sindbad to Varanus Island infield pipeline	25 mm concrete weight coating 4 mm asphalt enamel coating	1992, 15 year design life	Only partially buried at shore crossing	Llittle information on CP design 1050 mm distance to 8” Harriet crude oil line
8” Harriet to Varanus Island oil line	Stabilisation by trenching and mattresses offshore, no concrete weight coating 4 mm fusion bond epoxy	10 year design life	Buried	Design similar to 8” Wonnich lines, the corrosion protective coating is not adequate for buried structures.

For cathodic protection to work, the section to be protected needs to be immersed in an electrolyte (or buried in wet soil of a low electrical resistivity). The pipelines crossing the Beach of Varanus Island are only buried in shallow sand (fast draining, high resistivity above water line) and the level/degree of coverage with sand is changing with the seasons. Therefore, the CP system for the shore crossing was not reliable and extra care should have been taken to ensure the integrity of the coating system (visual inspections, excavations and/ or intelligent pigging). To rely on CP measurements to verify that the pipelines are protected against corrosion for the section where the incident took place shows a lack of understanding of CP.

Table 2: Other pipelines on Varanus Island built around the same time as 12" SGL

Pipe	Pipe details	Date installed	Surface/ buried at rupture site	Observations (by Rolf Gubner):
16" 'Wonnich' pipeline	75 mm Concrete weight coating 4 mm Asphalt enamel corrosion coating (sub-sea section), 1.5 mm Trilaminate (land section)	1998/9, unknown design life	Surface on-shore	Corrosion allowance: 0 mm Design: above ground Application states that AS 2885 and SAA Pipline code apply, CP according to AS 2832.1 Location of insulation joint not clear, no details on actual CP design available
2 identical 8" 'Wonnich' pipelines multiphase flow (inhibited oil, wet as)	0.4mm Fusion bonded Epoxy (FBE), field joints: coat and wrap, heat shrink near shore No concrete weight coating Note: A letter send to the then Department of Minerals and Energy by The Apache Energy Limited (DME271. DOC dated 3-Dec-98) states 0.4 mm FBE as external corrosion coating in section 2 Basis for Design of the pipeline	Application in 1998	Surface onshore	No CP for on-shore section (since above ground), insulation flange at low water mark/however, this description has been altered later – is there an insulation flange? • maintain and monitor a system for monitoring and control of corrosion and stress corrosion. • adequate earthing • corrosion allowance (pipe-wall thickness) according to AS 2885.1 • measure cathodic potential and voltage gradients within three months of commissioning, later inspection intervals to be agreed with the Director (WA Department). • wall thickness measurements after 2 years and 5 years thereafter. • Epoxy coatings are not suitable for exposure to sunlight.

The reports that have been contracted to investigate the 12" Sales Gas Line samples concentrated on the extent of corrosion, the fracture, the microstructure and mechanical properties of the pipeline material and to some extend on the composition of the corrosion products (elemental analysis). Little data appears to have been collected about the type of coating, the thickness, the adhesion of the coating at locations on the pipeline unaffected by the heat of the fire. Little data was obtained about the condition of the pipelines across the entire length of the shore crossing. This data would have been extremely helpful to reconstruct the corrosion rates, the efficiency of the CP system, etc. Without this information, any attempt to construct the corrosion failure mechanism is based on assumptions and similar cases. The lack of such potentially significant data may be indicative of a superficial investigation by the operator despite liaison with regulators and more than 12 months having elapsed since the 3 June incident.

3. Observations made during the review of the reports on the competence of personal/contractors

The JP Kenny Technical Specification for the 'Pipeline Design Basis' (39-1-04-003-K) for the 12" sales gas pipeline and the 12" Sinbad/Campbell line states in section 3.2 under the heading Pigging: *'Also, the Sales Gas Line may from time to time be inspected by an Intelligent Pig to monitor the internal condition of the line'*. Thus, in the design, inspection by intelligent pigging was taken in to account, although for the purpose of internal corrosion inspection.

The design document for the cathodic protection system (JP Kenny, job no 0100802) divided the pipeline into two zones: one zone (near zone and far zone). The near zone was referred to as the product inlet zone which is at elevated temperatures. The shore crossing was not taken into account, or treated differently. It is stated on page 4: '*All pipelines are analysed as exposed, since no burial has been specified'*. Here seems to be a gap between design criteria and real conditions at the shore crossing. The CP design assumed that pipeline will be submerged in sea water. The partial burial in sand was not factored in. However, as outlined in the following section, this gap became apparent in several reports and latest in 2004 (Netlink Report) when significant corrosion was observed on the 12" sales gas line and the following should have taken place: a) the corrosion protection systems of the beach crossing on Varanus Island should have been revised carefully and b) the corrosion protective coatings of the pipelines on the beach crossing should have been carefully inspected and repaired (even under buried sections).

Brian Martin reviewed the different inspection reports and described them as inadequate and not conforming to the AEL Onshore Pipeline Inspection manual requirements. In addition to his findings the following observations can be made (in chronological order):

The Apache Energy *Sales Gas Pipeline Survey Report* issued on 20/2/95 and updated with photos on 8/7/96 was carried out on 7/1/96 by Peter Beckford of Apache and Mike McCoy of Westcor from KP0 to CS1 on the mainland section of the Sales Gas Line (SGL). The pipe to soil potential measurements, according to the report, confirmed both full protection at this end and confirmed isolation from the frame and onshore pipe. For the onshore SGL mainland the reports concludes that the pipe is fully protected for the entire length but noticed very dry surface soil conditions except the tidal flats section. The survey was conducted approx. 3 weeks after heavy rains were reported in the area. The fact that the soil was very dry should have triggered a soil resistivity test/mapping to confirm that the pipeline would still be protected (electrical continuity) in areas with low soil conductivity.

Apache's *Statutory Inspection Manual* was last revised on 11 September 1996 and included annual inspections for the onshore section of the 12" SGL. However, the manual made no reference to the inspection of the short section of the 12 inch SGL at the shore crossing onto Varanus Island covered by licence PL12. The Manual notes the general requirement for pipeline inspections specified in AS2885:1987 and that this includes wall thickness measurements and corrosion protection surveys. The Manual also stated that pipeline inspections include 'Internal inspections using an intelligent pig' but this was not applied to the 12 inch SGL. The Manual was superseded in mid 1997 by an Underwater Pipeline Inspection Manual and an Onshore Pipeline Inspection Manual with the former itself superseded in June 2003 by an Underwater Inspection Manual.

The Apache Energy *Onshore Sales Gas Pipeline Cathodic Protection Survey* report was issued on 18/12/97 and produced jointly with Westcor Engineering Pty Ltd. It can be noted that the same consultant company had been used for performing this survey. The report stated again that the Surface soil conditions were very dry except the tidal flats section. The purpose of the survey was to test the effectiveness of the installed cathodic protection system for compliance with the original design criteria. However, there is (again) no mention of the soil resistivity made, thus whether the objective to verify the functioning of the CP system has been reached is questionable.

A *Cathodic Protection Review* by Ferrum Technology Pty Ltd is linked to a 'QCL International Review of Apache SGL Cathodic Protection Survey Reports' and was dated 23 January 1997. The report abstract states that full CP-design for the new 12" pipeline will require soil resistivity data. The report also states that it was noted that the current requirement for the pipeline is very dependent upon the moisture content of the soil and points out that it is difficult to quantitatively determine the condition of the extruded HDPE coating based solely on the data obtained from the performed CP survey but assumes that, since the current density had not increased with time, the coating condition had not significantly changed since 1993. Furthermore, the report does not recommend performing a DCVG survey at the time, but suggests doing this in conjunction with the installation of the new pipeline. To my knowledge, such a survey has not been performed. The report also concluded that it is not possible to determine the need for an intelligent pig inspection survey based on CP data obtained and suggests that to continue the (for offshore pipelines mandatory) intelligent pigging survey, when performed, over the onshore section of the pipeline.

This report raises the following concern: the abstract requires that soil resistivity data should be supplied in order to design the full CP system for a new proposed pipeline. In the main section of the report it is accepted that the Pipe to Soil potentials are sufficient to determine if the CP system is working, assuming electrical continuity in the soils along the pipeline. Furthermore, it is stated that the current demand is very dependent on moisture content of the soil. This could be an indication of a failed coating but it was not deemed necessary to investigate this further. The results could indicate that the resistivity in the soil between the anodes and the pipe is often too high for the anodes to provide the protection current across the length of the pipeline, opening the door for pockets (sections of the pipeline) of little/or no CP protection. Furthermore, it has been written that the current density has not increased with time, which is an erroneous statement. The current density is measured in Ampere per surface area. The current per surface area needed to protect a steel pipeline is defined and the base for the designing the CP system. The current density can only increase with an increased protection potential or lower soil resistivity. For measuring the current density, one needs to know the exposed surface area, which one will only get by digging up the pipeline and performing a visual inspection. Such a report should not have been accepted by the client (Apache).

A report by Stratex Pty Ltd, dated 11 August 1998, 12 and 16 inch Sales Gas Lines offshore section – AS 2885 risk assessment reviews the offshore sections of Apache's 12 inch SGL against the then risk assessment material incorporated in Australian Standard AS 2885 prior to the installation of the 16 inch SGL in 1999. Apache personnel, consultants and others conducted workshops in June and August 1998 that identified nine action items. Action item three reads: *'External Corrosion – At the Varanus Island shore crossing: Ensure the procedures cover the need for inspections at the shore crossing on Varanus Island.'* An Apache employee is listed as 'action nominee' to meet an 'action close-out date' of 30 September 1998. A more detailed attachment noted that a 'credible' threat existed at the mainland shore crossing section of the proposed 16 inch SGL and listed a procedural measure of 'Inspections at the water level'. The same attachment also cited the 'credible' threats of 'Stray current corrosion – lines close to each other', 'Debris in trench', 'Possible breakdown of coating from abrasion where pipelines cross' and 'Failure of the concrete coating'. Stray current effects and breakdown of coating are issues that have more general applicability and may involve adjacent pipelines. It can be noted that no reference in the context of stray current effect or failure of the concrete coating was made to the 12 inch SGL at the Varanus Island shore crossing. This risk assessment, although not complete and ignoring the existing structures, pointed in the right direction. However, why was the risk assessment only performed for the new 16” line and not for the existing pipelines? The conditions of these lines are also changing due to possible interference from the new pipeline and why has there not been a follow up report on the possible threats?

A second report by QCL International *Corrosion risk assessment and inspection scheme* (September 1998) commissioned by Apache on corrosion risk assessment covered a number of facilities including the entire 12 inch SGL. The QCL report noted that Pipelines are at risk from external corrosion. Further the report stated that all pipelines under study in this report are protected by external coatings and cathodic protection. The report assumed that the cathodic protection system was properly designed, but pointed out that a design review of the CP system was outside the scope of this report and that if CP tests show significant unacceptable performance, physical pipe inspection will become necessary. It becomes clear that a full risk assessment for the 12” SGL pipeline was not performed, since the review of the design of the CP system was excluded from this report.

The QCL report stated that the 12 inch SGL faces a most significant risk due to external corrosion in the coastal and onshore sections. The focus was on the mainland shore crossing end of the pipeline where mangroves are located, but some of the sea water conditions and tidal effects have been mentioned pointing out that the coastal section is more at risk of external failure than any other part of the pipeline, which are potentially common to the Varanus Island shore crossing section of the same pipeline. It is worth noting that the 1998 QCL report includes the heading ‘On-line Inspection’ and states:

> *The requirement for intelligent pigging on this line is dictated by the external corrosion hazard, particularly in the coastal mangrove section of the line. The most serious risk to the continuing integrity of the pipeline is where coating has disbonded, creating a region of wet, bare metal shielded from cathodic protection current. Corrosion may occur despite adequate cathodic protection potentials. This is a risk on all coated pipelines, but is most significant on onshore/inshore lines, particularly under tape wraps and shrink-wrap type field-weld coatings. The only methods of detecting such failures are either to excavate all field joins, or to run an intelligent pig. The economic and safety consequences of a failure of the Sales Gas pipeline, coupled with the difficulty of surveying the*

> *coastal section, and the risk of a coating disbondment failure mean that regular intelligent pigging of the line is justified. To save cost, this survey may be concentrated on the coastal and onshore sections of line. The period is arbitrary – a figure of five years is suggested, meaning that an intelligent pig run will be necessary next year. Further surveys will be required depending upon the results.*

Running an intelligent pig was highly recommended by the contractor in 1998, but has never been performed. This is another example where critical information has not been acted upon, other than to modify the corrosion management strategies on paper.

On 24 February 2000, Apache issued a *Production Facilities Integrity Corrosion Management Strategy* which focussed on the threat posed by corrosion, including corrosion to pipelines and corrosion under insulation (CUI). It listed a significant number of management and technical staff and consultancy positions with roles and responsibilities to address this threat. The document states:

> *It is a major objective of the corrosion management system to ensure safe working and avoid environmental damage. This will be achieved for offshore installations, onshore plant and pipelines by meeting the statutory requirements in both their current and emerging forms. The Corrosion Management Process conforms to the requirements of the current legislation as provided in the Petroleum (Submerged Lands) Acts. It also observes the requirements of the Australian Standards that are expected to be applied by the legislation and by operating licences and consents issued in accordance with the legislation.*

The Apache document goes on to define the policy and practice of Corrosion Risk Assessment (CRA) in terms of failure likelihood and associated consequences. In discussing monitoring, the document notes the various purposes of pigging pipelines using different types of pigs, including for inspection:

> *'Intelligent' pigging of a new pipeline prior to operation will provide an initial 'signature' of the conditions of the pipe internal walls and wall thickness. Thereafter intelligent pigging runs are scheduled to inspect the condition of the pipeline. Factors affecting the schedule and frequency that relate to corrosion control are: ... increased corrosion rates indicated by other monitoring devices.*

Among other testing methods listed in the Apache document are monitoring cathodic protection, use of corrosion coupons, sand probes and non destructive testing (NDT) techniques which include 'Visual Examination, UT (A Scan and B Scan), Radiography, MPI, Dye Pen, pit depth gauging, boroscoping and ACM pitting depth \

surveys'. Looking at the data provided, this management system has not been applied fully to the 12" SGL that ruptured. If it would have been applied, the coating failing and the corrosion on the pipeline would have been detected in time to have avoided the incident.

JP Kenny produced for Apache a *Pipeline Asset Inspection Strategy* issued for comment on April 2000, only two months after the Apache's *Production Facilities Integrity Corrosion Management Strategy* was introduced. The JP Kenny report included a table 2.1 'Summary of Proposed Prescriptive Inspection Strategies' stating for the 12 inch SGL that it had been operating since 1993, had a length of 100.06 km, external survey was to be at two yearly intervals CVI by diver/ROV, internal survey was to be at five yearly intervals by ultrasonic testing, and CP survey at four year intervals with CP measurements by diver/ROV. In the same table, the 1992 Campbell/Varanus Island Infield line of 31.15 km differed only with respect to internal survey being intelligent pigging at five year intervals instead of ultrasonic testing. The 1999 16" SGL had the same internal testing proposed as the 12" SGL. Both intelligent pigging and ultrasonic testing was referenced to AS 2885.3 and the latter was stated to be 'Ultrasonic testing of pipewall using equipment mounted externally on prepared areas of pipeline. Air divers required. Note this operation requires pipeline coatings to be removed.' Cathodic Protection was linked to applicable codes DNV RP B401-1993 and AS2832.1-1985. The objective of external inspection was stated to be 'stability' of the pipeline, for internal inspection it was 'establish 'integrity' of the pipeline, and for cathodic protection it was 'To ensure that the cathodic protection system (sacrificial anodes) continues to protect the pipeline and associated infrastructure from corrosion'.

An attachment to the JP Kenny report provided more detail on each of the pipelines with the Sales Gas Pipeline 12" from Varanus Island to Compressor Station CS1 supplying dry gas to Alinta gas trunkline, stating the design parameters and specifying the external corrosion protection of 4.5 mm Asphalt Enamel coating and sacrificial cathodic protection. In respect to internal corrosion, it stated that no internal corrosion is expected since the gas is treated and dry. Another table of 'Pipeline Licence Inspection Requirements' noted for the 12 inch SGL that external survey requirements were 'Annual post-cyclone', internal survey requirements 'In accordance with approved plan (Code), CP survey requirements 'Annual corrosion & damage inspection of above ground pipeline (Code), and Pipeline Code AS2885-1987. It was noted that the short onshore sections where applicable, but not the hydrocarbon processing plant where piping is covered by ANSI B31.3. AS2885.3-1997. Clause 5.2.2 states:

The regularity of assessment should be based on the past reliability of the pipeline, current knowledge of its condition, the rate of deterioration and statutory requirements.

The report also tabulates a summary of code requirements and for AS2885-1987:

External Survey Requirements … Pipeline route to be inspected on an approved periodic basis or when damage may have occurred. … Coated Pipeline – external coating survey whenever visible, interval not specified. … Internal Survey Requirements … Otherwise by approved method, interval not specified. … CP Survey Requirements … Review within 1 year of installation. Monitoring at 5 year intervals (may be shortened towards end of life).

A table with the JP Kenny recommended program included for the 12 inch SGL External Survey at two year intervals, Internal Survey at five year intervals, and CP Survey at four year intervals. Finally, the 12 inch SGL was listed among 'Pipelines to be inspected by ultrasonic testing at critical locations' 'at five year intervals' 'Ultrasonic Testing at regular separations and identified 'hot' spots', and 'Necessary to confirm moisture control system' to ensure dry gas. Many of the points raised in the report seem not to have been implemented into an inspection programme for the 12" SGL.

QCL International provided the then WA Department four Apache Asset Integrity Management Audits on 27 July 2000. A Lloyd's Register Corrosion Data Management Procedure Audit Checklist dated 5 May 2000 stated that a centralised corrosion database did not exist at the time and that asset lives have not been calculated. An audit of 24 May 2000 re Corrosion Data Management Procedure- East Spar Monthly Corrosion Reports states:

Only calculated Asset lives, based on measured corrosion rates, must be added to the report. One concern raised by the audit was the completeness of the reports. It was found that a lot of information to be provided by Peter Beckford [corrosion technician] was missing on a regular basis. In addition, it was not possible to ascertain the accuracy/quality of the data collected on the Island. It was found that QCL could not answer a lot of the questions related to data gathering, and could not show evidence of compliance with the procedure regarding frequency of data gathering and accuracy of data.

It is surprising that the obvious lack of corrosion inspection data and the resulting uncertainty of the condition of the pipelines did not trigger an immediate response to ensure the integrity of the pipelines.

An Apache *Energy Corrosion Management System Pipework Inspection Procedure* was issued on 04/02/99 and revised on

19/06/01. The focus was on pipework rather than pipelines. It stated that 'Visual inspection should only take place by competent inspection personnel as laid out in AS 4041:1998 Section 8.1.3, and AS 4481:1997 Section 4.' A table of anomaly criteria, actions and checks included for corrosion pits greater than 2 mm or leading to a wall thickness less than the anomaly WT where stated on the datasheet. On wall thickness it was also stated 'Less than 80 per cent of nominal wall thickness of pipework where no figure given and 90 per cent for structure'.

In June 2002 and July 2003, Auscor Pty Ltd undertook *Onshore Cathodic Protection Surveys* for Apache on the 12 inch and 16 inch SGLs. The reports cover only the mainland end of the pipelines. The June 2002 report refers to Australian standards AS2832.1 and AS2885 and states that: 'the minimum protective potential for gas pipelines is -0.85V [with respect to a copper sulphate reference electrode]. This criterion is increased to -0.95V for the tidal flat section where there is a likely presence of sulphate reducing bacteria'. Further, it is stated that 'both pipelines are fully protected with potentials relatively consistent and ranging from -1.145 to –1.272V, well above the minimum -0.85/-0.95V criteria.' After an extended 18 month dry season, the 12 inch SGL range was from -1.176V with CP off to -1.272V with CP on. In July 2003, after 'a period of intermittent heavy rain which would have increased general soil moist levels to pipe invert level' the 12 inch range was from –1.085V to -1.312V with CP off and from -1.242V to -1.404V with CP on. It is again surprising that the contractor has not picked up on the soil resistivity and the associated risks, as at a potential of larger than -1.24V (vs. Copper/Copper sulphate) cathodic disbondment of the coating might take place.

Apache contracted QCL International Ltd to conduct a review of its Varanus Hub pipelines and on 6 February 2004 the review team delivered their report Review of Apache Energy pipelines. Its summary of results included a section 'Missing Data and Assumptions' which included the finding that:

> *In general it was found that very little inspection data was available for onshore pipeline sections on Varanus Island, shore zone sections and subsea risers. The onshore pipelines on Varanus Island are monitored visually during standard operations on the island and inspection data is therefore often not documented. … At present the shore zones do not seem to be included in either of the standard inspection work scopes.*

The report considered pipelines in separate zones, according to operating environment changes, with the following five discrete sections on the SGLs considered: Onshore pipeline Varanus Island; Shore zone pipeline; Subsea pipeline; Shore zone; and Onshore pipeline mainland. The consequence of failure for each section was assessed against four factors: personnel safety, asset damage, production loss and environmental damage.

In relation to shore zones, QCL stated that:

> *these sections are considered to be protected by the subsea pipeline anodes. The probability of section failure due to external corrosion is therefore assessed on the basis of CP readings and anode wastage inspection data. The primary indications of external corrosion are assumed to be sudden changes in CP trends and high or low CP readings accompanied by a very high or very low anode wastage rate.*

This statement is not correct: a coating often fails gradually; therefore the corrosion protection current (anode wastage) will grow gradually. The Varanus Island 'shore zone' section was described as being 0.32 km long beginning at the isolation joint (KP69.76) and ending in the shallow water shore zone (KP69.445). It is also noteworthy that the lack of corrosion inspection data was noted. Again, the report assumes that the CP system had been designed correct and would function properly, which was not the case (partly buried pipelines). It seems likely that the review has been done at a desk without any physical inspection of the lines. It is surprising that the CP design has not been reviewed, or at least the question been raised to overlook the system?

The QCL report also stated that:

> *Alternatively no cathodic protection may be used on short onshore pipeline sections with an external corrosion protection coating. The availability of inspection data is again used to provide a confidence factor for the assessment of each system. ... The pipeline inspection history is then reviewed for indications of damage to the external coating and the isolation joint.*

This statement is risky in itself, to rely on only one corrosion protection mechanism is increasing the risk for failure. Furthermore, if relying on a corrosion protective coating only, this coating needs to be adequate. Confusingly, the Varanus Island 'shore zone' was then stated to be 0.07 km long from the pig launcher on Varanus Island to the isolation joint on Varanus Island (KP69.76). This section is in the main plant area above the beach crossing and the other side of the joint cited above. The report stated that:

> *No inspection data was available for the onshore section on Varanus Island or the shore zones at Varanus Island and the mainland. This has resulted in increased risk rankings in these sections.*

The appendices show that there was no data of any kind available to QCL on the 12 inch SGL in these sections including from CP surveys or physical inspections. All of these sections were assessed as of 'medium' risk of external corrosion with consequences being 'critical' and the overall risk level 'high'. The QCL report recommended that a general visual inspection of the pipeline be implemented as soon as possible and assessment rerun for these sections. Unlike in 1998, there was no reference by QCL to intelligent pigging, which is surprising, since intelligent pigging is becoming more and more common in industry with every year that passes.

Another report statement that raises concern about the competence of the involved persons is the following statement taken from the Auscor Pty Ltd *Varanus Island Offshore Pipelines-Onshore Section Cathodic Protection Survey* August 2004, 16 February 2005 report.

> *Survey potentials of offshore pipelines at buried sections adjacent to onshore insulated flanges receiver or launcher skids … pipes have additional magnesium alloy sacrificial anodes installed adjacent to insulation flanges … provide supplementary protection at onshore coating defects and to offset interference effects from the crude storage tank CP system(s). Maintenance works are in progress to replace depleted anodes and upgrade a number of these facilities.*

Here it is clearly stated that interference between different structures are of concern, in this case it was even expected and a recommendation proposed on how to mitigate the problem. However, the proposed solution will not work (see the Brian Martin report).

Netlink Inspection Services Varanus Island ultra shallow water and onshore pipeline inspection – 12 inch Sales Gas Line - Apache contracted Netlink Inspection Services to undertake a visual inspection of the 12 inch SGL from 16–18 October 2004 that included the shore crossings. The report states that:

> *All items of corrosion noted on the Sales 12" Gas Export line were on the western side of the Cyclone Protection Enclosure [including] width 500 mm length 300 mm corrosion visible under wrap. ... Close to the beach, and as the pipeline enters the shore, there are two sectors of missing weight coat. As the 12" Sales Gas Export line enters the sand dune at the end of the North Eastern beach on Varanus Island there is also a minor crack in the weight coat.*

If cathodic protection would have been working as designed, no corrosion should have been visible under the flaking wrap (with the exception of crevices). It is very surprising that the findings did not result in a full investigation of the pipeline condition at the shore crossing and initiation of repair work. The Netlink report provides a clear indication that the corrosion protection system for the 12” SGL has failed and that the CP system was not working as designed. Acting on the Netlink report would probably have prevented the incident (unless the corrosion was already so advanced that excavating the pipe would have resulted in a rupture of the pipe).

The Apache *Annual summary report* of inspection and corrosion management activities report was drafted in May 2005 and issued on 4 January 2006. In relation to the 12 inch SGL, it summarises a Netlink Services inspection of 16 October 2004. It also includes extensive material on inspections, including intelligent pigging, of other pipelines completed during 2003, 2004 and in May 2005. However, no repair work appears to have taken place, which could have prevented the incident.

In the Apache issued *Onshore Pipeline Inspection Manual* (22 March 2006, original issued in 1997, updated in 2003) provided the overriding philosophy and expectations for onshore pipeline inspection. The manual preface stated:

> *This Onshore Pipeline Inspection Manual covers the inspection of all the onshore sections of these pipelines, defined as that part of the pipeline between the landfall to the pipeline termination or pig launcher/receiver.*

However, its description of coverage then becomes somewhat confused. The ‘scope of manual’ section states that the SGL covers licence TPL8 from Varanus Island to the mainland with no mention of the extent of pipeline covered by PL12, which applied to all six pipelines at the north east shore crossing on Varanus Island. It then states: ‘two SGLs … transport processed dry gas from East Spar and the Harriet Gas Gathering project on Varanus Island to the Alinta Gas pipeline at compressor station CS1, 30.3 km of both the pipelines is onshore and thus is covered by this manual.’ The Manual stated that pipeline inspection should include:

> *…an audit of corrosion control facilities to assess their effectiveness. This includes cathodic protection systems, pipeline coatings. … The pipeline licence reinforces the requirement of AS2885.3 … [which] states that pipeline surveillance and inspection shall be conducted at a frequency based on the past reliability of the pipeline, historical records, current knowledge of its condition, the rate of deterioration and statutory requirements. …this inspection frequency approach introduced in 2001, AS2885.3-1997 gave inspection frequency as annually. It is envisaged that no risk assessments have been conducted, and annual frequency is to be applied until these documents are in place.*

The Manual provides direction for corrosion control procedures. Above ground pipeline coatings should be addressed with particular attention to crevice areas like pipe supports and the underside of the pipeline, as well as areas of blistered or disbonded coating. It states that assessment of below ground pipeline can only occur through monitoring cathodic protection data or the use of special coating defect surveys such as Pearson or DC pulsed or Voltage Gradient surveys, and visual surveys where the pipeline is exposed at selected locations. The Manual also provides direction on assessments of cathodic protection. It states that test results outside the range of 850 to 1200mV vs. Cu/CuSO4 are considered 'anomalous' and 'shall be' subject to detailed evaluation. However, this does not appear to have been implemented routinely.

The 2007 ModuSpec Gap Analysis report notes under 'Corrosion' that:

> *The European Gas Pipeline Incident Data Group identifies corrosion as the third highest cause of gas leakage. [Further, while the QCL report had assessed external corrosion] The QCL methodology states that probability of failure in this area is based on the inspection data of anode wastage and CP reading. AS2885.1 lists a number of causes of external corrosion, the implication being that these causes should be considered. There is no evidence that this has been carried out.*

ModuSpec's recommended way forward is to review threats and reassess pipeline risks for each pipeline in accordance with AS2885 and produce a:

> *...Pipeline Management Plan for the whole network including: Risk of significant pipeline events and other risks to the integrity of the pipeline; Measures to reduce risks to ALARP; Arrangements for monitoring, auditing and review; Review of the Forward Action Plan.*

This is the first report that recommends a Pipeline Management Plan for the whole network. It took from 1989 to 2007 for this recommendation to be made. If this had been done/followed in the design and installation of the two 12" pipelines, or at least with the installation of the 16" sales gas line, the faults in CP should have been detected and the incident could have been avoided.

A September 2007 Apache *Onshore Pipeline Inspection workbook* lists the poor onshore pipeline survey history for the 12 inch SGL since installed in 1993 (sic). According to AS 2331, annual inspections should be carried out for the onshore section of CP pipelines. This is also a requirement of performing annual inspections after the hurricane season. These inspections have not been performed in a number of years (1994, 1995, 1998, 2002, 2003, 2005 at least and no data was sighted for 2006 and 2007). A section of the workbook report assessing the visual assessment of the pipeline stated that the onshore/offshore tie-in point, the isolation flange and the pipeline coating were not seen as they were completely buried; and that the buried section was weight-coated, making the anti-corrosion coating inaccessible for visual assessment. Just because something is not freely accessible does not mean it does not have to be inspected. If there was indeed an insulation flange at the waterline, then how could the pipeline reach the CP potentials as stated in the reports? Already on 24 February 2000, Apache issued a Production Facilities Integrity Corrosion Management Strategy which focussed on the threat posed by corrosion, including corrosion to pipelines and corrosion under insulation (CUI) (see above). The question remains open why this CRA strategy has not been implemented on Varanus Island?

An Auscor Pty Ltd – Apache Energy *12 & 16 inch Sales Gas Lines onshore section cathodic protection annual survey 2007* report of March 2008 only included the mainland onshore 12 & 16 inch SGLs from KP0 to KP31.3. It stated that the pipelines are fully protected over all sections with CP off potentials very uniform and with no significant change from previous levels. Since the majority of sacrificial anodes were found to be depleted and hence disconnected, an impressed current CP system located at the CS1 inlet station was proposed. Comment: the anodes are normally designed for the full life time of the structure, taking normal coating degradation into account. If the anodes are found to be depleted after only 16 or respective eight years of service respectively (assuming these were the first replacements that occurred), there must have something gone wrong: either the design, or the coating has failed somewhere, or the current demand is much higher than expected. Therefore, the observation of depleted anodes should have raised concerns and warranted further investigation.

A Sales Gas Lines *5-Year Integrity Review* was undertaken for Apache by Subsea Developments (Australasia) Pty Ltd and completed in May 2007. Its stated purpose was ‘to provide a summary of the status of the SGLs with respect to their current condition and the activities performed in the ongoing integrity management over the period’ and ‘includes inspection and corrosion activities performed during the period from 2000 through to December 2006’ for the 12 inch and 16 inch pipelines. It cites the 2004 QCL report and the two April 2007 ModuSpec reports and states, based on the CP and other data reviewed, that ‘The SGLs are generally in a good condition based on the monitoring and inspection activities reviewed and summarised in this document’. It concluded:

There are no findings from the integrity management processes performed for the Sales Gas Pipelines that provide any reason for any changes to the ongoing IMR activities that are not already being addressed in the current risk assessments and anomaly tracking and close out practices. The AEL Pipeline Integrity Management process is generally following the requirements of AS2885 and any specifics included in the Pipeline License for the Sales Gas Pipelines.

This statement opened the door for interpretation whether to apply AS2885 or not, since the Sales Gas Pipeline was clearly not inspected at the prescribed intervals of five years (offshore), yearly (on shore), which is prescribed through AS 2885.3 (CP shall be monitored in accordance to AS 2831.1) The report also notes that planned Apache activities will include 'Inspection of onshore pipeline, to allow wall thickness monitoring, Every three years, 2007 – UT -Inspection'. Furthermore, there is also a diagram that includes intelligent pigging linked to the onshore integrity plan/schedule but it is not clear if this includes the Varanus Island shore crossing or just the mainland. There are obviously gaps in the risk assessment and integrity management plans for Varanus Island still in early 2007.

At the same time, ModuSpec Australia Pty Ltd produced two reports *Review of recommendations from 2004 pipeline risk assessments; and Gap Analysis: Comparison of QCL review with the requirements of AS2885 and the Petroleum (Submerged Lands) Pipelines Regulations 2001* dated 10 April 2007, with reference to all Apache pipelines related to Varanus Island. The Gap Analysis was undertaken as part of the work towards a proposed Apache pipeline management plan (see separate section below). With respect to the 12 inch SGL, the report notes that the pipeline:

...is 100 km long. The pipeline is constructed of carbon steel and has an external corrosion coating of Asphalt Enamel from Varanus Island to the Mainland and is coated by Extruded HDPE on the onshore section of the Mainland. Cathodic protection is achieved by the use of bracelet anodes. The pipeline was designed to the AS2885-1987 standard and installed in 1992.

The Moduspec report states that 20 recommendations had been made with respect to the pipeline with three remaining open, including one regarding external corrosion on the onshore mainland section.[155] The report's 'summary of integrity' table includes the four categories of external corrosion, fatigue and instability, impact/

155 The 2004 inspection of the pipeline by Netlink was 'reviewed in a April 2007 audit by ModuSpec, with the comment that 'CTC-2 CP survey deemed protected against external corrosion under aerobic and anaerobic conditions'. It was deemed that this corrosion issue had been closed in October 2004.

accidental damage, and internal corrosion; and lists five pipeline sections including 'Onshore Pipeline Varanus Island' and 'Shore Zone Pipeline Varanus Island'. The 2004 ModuSpec Gap Analysis findings state with respect to QCL's 'risk identification' in 2004 that while the threat posed by a likelihood of failure as a result of external corrosion was assessed against four consequence factors – personnel safety, asset damage, production loss and environmental damage, threats not assessed included 'external interference, operations and maintenance, design defects, material defects, and intentional damage' and:

> *In addition, the threats were not categorised in accordance with AS2885.1 (i.e. those which are not credible; those which are controlled by external interference protection; those which are controlled by design and/or operational procedures or residual threats requiring further risk evaluation).*

In terms of regulations 25 to 27 of the Petroleum (Submerged Lands) Pipelines Regulations 2001, ModuSpec concluded that:

> *Most of the information required for a description of the Pipeline Management System is not provided. The following aspects are omitted: Risk of significant pipeline events – This information relates to the incomplete identification of threats and that hazardous events have not been identified in accordance with AS2885.1; The measures used to reduce risks to ALARP – These relate to fact that the identified threats have not been categorised in accordance with AS2885.1; The management arrangements – This omission relates to the fact that risk management has not been carried out in accordance with AS2885.1.*

However, an Apache Integrity management personnel and competencies description document was issued on 24 January 2008. It includes a list of roles and responsibilities related to integrity management, including for pipelines. The document also stresses the importance of contractor competency and notes that 'Inspection and NDT is a critical part of corrosion and integrity management'. In this light, Apache should have been aware of the lack of competence from both sides, however, it is most likely that it would have been too late at that stage to have inspected the 12" pipeline.

In summary, there are two underlying problems in respect to the integrity management of the pipelines on Varanus Island.

1) It can be noted that there seems to be no or little effective communication between the field corrosion technician and the management. Reports produced by either Apache's own technician or hired consultants do not result in any satisfactory

reaction to mediate or mitigate corrosion damages. If a trained CP specialist had been asked to analyse the data from Varanus Island, he would have demanded additional data to verify the function o the CP system. Warning flags have been raised since the first CP reports in 1995. It seems like Apache reacted to each report by commissioning another study or to implement new guidelines and procedures on how and what to inspect, but the prescribed work was not performed adequately. The ultra shallow water report by Netlink (2004) had all the indications documented that the CP-system for the shore crossing was not working as planned. If acted upon, the incident could have been avoided.

2) The qualification of the contractors and staff on Varanus Island can be questioned. The principles of Cathodic Protection do not seem to be understood by the personnel performing the tests and submitting the reports.

The above could have been noticed at the management level at Apache but also at the regulating authorities, if corrosion trained experts had been consulted for reviewing the reports.

4. Possible corrosion scenarios

As mentioned above and explained in detail in the Brian Martin report (document No 215.002d), Cathodic Protection using sacrificial anodes in sandy beach environments will not work above the waterline. The beach sand is well draining and only as long as it is logged with seawater the resistance in the soil is sufficiently low to allow CP to work. That means that the steel structures above the low tide level will only be intermittently protected by CP. A confidential Singapore-based consultancy ALERT/*Burgoynes Varanus Island Facility Incident Report* produced for Apache and dated 16 September 2008 shows that the original rupture of the 12 inch SGL was clearly in the inter-tidal zone not above normal high tide since by 6 June 2008 the explosion crater was largely refilled with wet sand via tidal activity as documented in a photograph.

An impressed current system might be used to overcome the limitation to some extent, but the applied potentials to achieve protection would be above the point for hydrogen formation, which in turn could result in cathodic disbondment of the coating from the pipeline.

4.1 *Coating failure due to lack of adhesion during application*

This corrosion scenario has been proposed by Brian Martin and is detailed in the report delivered to the Department of Mines and Petroleum, document No 215.002d, dated 06. May 2009. In this report the primary cause for the corrosion failure was attributed to a possible lack of adhesion when the coating was applied, or a loss of adhesion early in the life of the pipeline. His argument is that a typical corrosion rate under disbonded coating would be in the order of 0.5mm per year, thus the loss of adhesion would have taken place early in the life to achieve the loss of 10 mm material. This is a plausible explanation, however, normally coating application is subject to inspection and a poor adhesion should have been noticed at the time of installation. However, a case in Texas showed much higher corrosion rates underneath a disbonded coating, the high corrosion rate was attributed to bacterial corrosion and significantly reduced cathodic protection due to shielding (Annex 11, NTSB Investigation of incident 24.08.1996). A similar case was investigated by TSB for a pipeline rupture (27.02.1996) where pipe to soil surveys were undertaken to ensure the existing minimum industrial norm of -850 millivolts (mV) 'off' cathodic potential and 100 mV shift potential were met'. Poor bonding of the tape wrap correlated with the corrosion at the centre of the failure (see Annex 11).

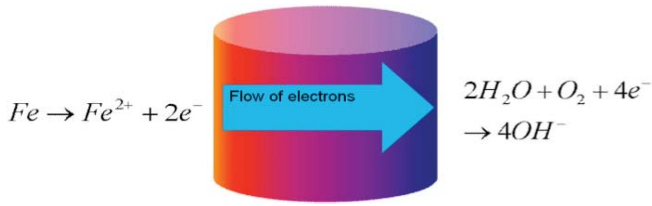
4.2 *Coating Failure due to interference with other structures*

There are six pipelines on the shore crossing close to each other (within a 10 meter wide area) that could interfere with each other. Extra Magnesium anodes have been installed close to the insulation flanges to mitigate interference from the impressed CP system that protects parts of the processing plant but the exact location of the anodes is not available. If these anodes (or some anodes) are above the waterline, they will have little to no effect because of the good draining properties of the sand. Furthermore, if not all the pipelines are kept at the same potential stray current corrosion may result. As an example of interference leading to failure the TSB investigation for the 29.07.1995 TransCanada natural gas pipeline near Rapid City, Manitoba, can be cited (Annex 11). Although CP potentials at the rupture site exceeded industry norms, the spacing of the pipelines was at the rupture site 'only' 7 m apart. It was noted that this spacing was below the operator's own minimum horizontal spacing requirement, which is stated in the report to be fairly common in the industry. The very close spacing of the pipelines at the beach crossing of Varanus Island at the incident location is clearly below that industry standard.

4.2.1 Direct Current Interference

If one assumes that, since the pipelines are of different age, it is likely that the pipelines have different potentials. Alternatively, if some of the installed magnesium anodes are in contact with seawater, others are not, different potentials of the pipelines could be the consequence. This, in turn, could result in a current that has been flowing between pipes at the first point of sufficient soil conductivity: in the tidal zone. The area where the current leaves the pipeline is the area where the steel dissolves (electric definition, the current flows from plus to minus). A schematic is given in Figure 1.

Figure 1: Direct Current Corrosion



This corrosion mechanism still needs the coating to fail first (loose adhesion to the steel surface) or to be initiated at a defect in the coating due to stone chipping or other mechanical damage during installation. The Brian Martin scenario is plausible and the relatively high corrosion rates of 0.7mm/year could be explained through direct current corrosion. It is also possible that the installation of the 16" sales gas pipeline in 1999 could have caused the interference to occur (e.g., disrupted adequate grounding), and the induced direct voltage and current was sufficiently high to lead to the adhesion failure of the coating (cathodic disbondment) and subsequent high corrosion rates of ca. 1mm per year could be responsible for the failure. It is also possible that intermittent DC-stray currents, e.g., due to inadequate welding procedures or grounding during the installation of the new pipeline, have caused the coating to disbond from the pipeline.

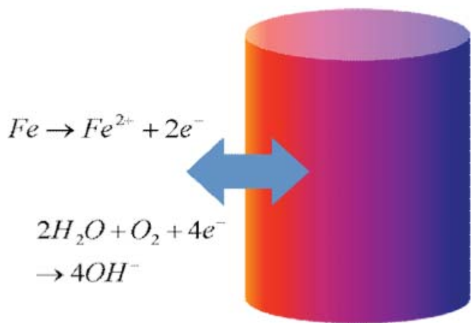
Supporting evidence: The corrosion damage (Figure 2) was observed at the 1 to 10 o'clock (viewed clockwise looking southwards towards the HJV plant) position of the 12 inch Sales Gas Line with datum location of the fracture identified at the 3 o'clock position, as well as the thickness measurements performed on the SGN showed most thinning at the same position (Section 3.3.1 Ultrasonic Inspection, Pearl Street report 8A5/MET10). The 8" Harriet crude oil pipeline could have acted as current collector and sink, as pictures indicate that it was in good condition.

Figure 2: 12 Sales Gas Pipe sections (12-SG-S, 12-SG-N & 12-SG-N-FE) and 12 Sinbad / Campbell Pipe section (12-SBC-N) laid out in similar positions as to that as removed from the Varanus Island site (Pearl Street Report 8A5/MET 9, Appendix 1, Image 5)

4.2.2 Alternating Current Interference

To my knowledge, no measurements have been made to evaluate the risk for AC-corrosion (although named in AS2885 and AS2331 as possible threats for pipelines). In a similar scenario as described under 4.2.1, but this time a faulty grounding inside the facility has induced an AC voltage into the pipe system (Figure 3).

Figure 3: Alternating Current Corrosion



AC-corrosion is often very localised and induced at small coating defects. It is unlikely that AC corrosion would cause the coating disbondment on such a large scale as observed on the 12" Sales Gas Pipe Line. However, AC-currents can pass through a damaged coating at greater ease (depending on the frequency) than direct currents. Taking a loss of adhesion of the coating system as given, a AC-voltage of 30V could have resulted in sufficiently high corrosion rates to cause this failure within a period of 10 years (dependent on the soil/sand resistivity at the location), a higher AC Voltage would have accelerated the corrosion rates, but not above 2 mm per year. The area where the rupture of the pipeline initiated (and the main corrosion on the sales gas pipeline was observed) might have been, looking from the facility, the first point where the beach sand was sufficiently wet at regular intervals for the AC current to exit the pipeline into the ground.

4.3 *Coating failure and cathodic disbondment due to CP-over protection*

The installation of magnesium anodes close to the processing parts results in a high protection potential. At potentials above -1.24V vs Copper/Copper sulphate electrode, hydrogen evolution is possible at the steel surface underneath the coating. The gas will lift off the coating from the surface, resulting in a loss of adhesion and water and gas filled bubble which will eventually rupture and expose the steel to the environment. Corrosion is possible inside the bubble, as the CP current cannot pass through the intact bubble at sufficient rates to protect the pipe. Even if the bubble ruptures, the CP current will not be able to protect the pipe inside the crevice between the pipe and the delaminated coating. However, since the CP system obviously did not work in areas where the coating has disbonded at field joints, as shown in the Netlink report from 2004, this scenario is unlikely. Nevertheless, cathodic disbondment could have taken place from other intermittent interference (e.g., inadequate earthing during welding work), resulting in damage to the coating, and the poor CP performance resulted in corrosion rates as stated in the sections above. Apache's documentation and consultancy reports warned of the danger of such disbondment but there was no evidence of follow-up evaluation.

4.4 *Summary*

There are four corrosion scenarios resulting in different corrosion rates. All four are plausible, but little data is evident to prove or disprove the one or other. Corrosion product analysis performed by PearlStreet Metlab (8A5/MET) showed high levels of carbon and oxygen to be present in several samples. This is indicative that carbonates have formed, which is further supported by the visual description of the corrosion products sampled. The presence of carbonates is an indication of high levels of cathodic activity; either due to stray currents or cathodic protection current, the latter could only be intermittently present when the waterline was above the pipeline. However, even at extremely high corrosion rates (2 mm/y) the corrosion should have been picked up during the annual visual inspections and CP-surveys, but latest in 2004 since it was explicitly shown in the Netlink report that the pipeline showed significant corrosion. The quality of the CP surveys did not take into account the poor conductivity of beach sand. Measuring the CP potentials is, therefore, close to meaningless, if not compensated for the soil resistance at the location of the measurement. Correct monitoring of the CP-current over a long period of time, e.g, over several high tide/spring tide cycles, could have revealed that the current necessary to protect the pipeline would have been well above design specifications at high water levels.

5. Standards related to cathodic protection of oil and gas pipelines

5.1 Australian Standards and Varanus Island

The JP Kenny Technical Specification for the 'Pipeline Design Basis' (39-1-04-003-K) for the 12" sales gas pipeline and the 12" Sinbad/Campbell line states in section 6.1 that he primary design code to be used in the detailed design was AS2885-1987. The design of the CP system for the offshore pipeline (including landfall up to the high water mark) was in accordance with DnV Recommenced Practice RP B401 for cathodic protection design (1986) and for the onshore section AS 2832.1 (1985).

The current iteration of Australian Standard *AS 2885: Pipelines – Gas and liquid petroleum* comprises several parts:

Part 0 (2008): General Requirements

Part 1 (2007): Design and Construction

Part 2 (2007): Welding

Part 3 (2001): Operation and Maintenance

Part 4 (2003): Offshore submarine pipeline systems

Part 5 (2002): Field pressure testing

Apache's current Varanus Island Hub Safety Case references the current AS 2885 (all parts) while the Varanus Island Hub Operational Pipeline Management Plan (PMP) references AS 2885.1 only.

The 12 inch SGL was designed and constructed in accordance with the now superseded Australian Standard AS 2885:1987. The superseded Standard includes prescriptive measures that are no longer present in the current Standard. These include the methodology to be followed in testing the efficacy of corrosion mitigation measures. It does not include a general prescription for intelligent pigging of all pipelines.

The current version of the Standard outlines a detailed risk assessment process to ensure that risks to a pipeline's operations are as low as reasonably practicable (ALARP). AS 2885.3 outlines operation and maintenance measures for pipelines. While not requiring intelligent pigging, the document notes that *'where available, intelligent pigging results should also be considered when assessing pipeline integrity.'*

Where a Standard is revised, good industry practice dictates that the operator reconsider the risks to those aspects of its operations that could be affected by the revision (this is also a requirement under the MOSOF regulations of the OPGGSA for those waters regulated by NOPSA).

AS 2885 has been written with onshore pipelines in mind. This does not include offshore pipelines or those pipelines at a beach crossing. Part 4 of AS 2885 disapplies itself, and the rest of AS 2885 with respect to all pipeline systems from the extreme high water mark down (i.e., the shore crossing zone and offshore areas). In its place, the Norwegian Standard *DNV OS-F101 Offshore Standard – Submarine pipeline systems* applies [text from AS 2885.4]:

> *All requirements for offshore submarine pipeline systems with respect to safety, design, materials, fabrication, installation, testing, commissioning, operation, maintenance, requalification and abandonment shall be in accordance with the latest edition of DNV OS-F101. The requirements of AS 2885.1, AS 2885.2, AS 2885.3 and AS 2885.5 are not applicable.*
>
> *Should DNV OS-F101 be silent with regard to any aspect of the scope then … guidance shall be sought in the first instance form other relevant Australian Standards.*

[text from AS 2885.4]

Apache's Varanus Island Hub Safety Case references this Norwegian standard, but its PMP does not.

The current (2007) version of DNV OS-F101 defines its scope as extending to 'the first weld beyond the first valve, flange, connection or insulation joint at a landfall unless otherwise specified by onshore legislation.' The aspects of this Standard that discuss corrosion mitigation for pipelines apply for the full scope of the Standard.

The superseded version of DNV OS-F101 excluded the shore-crossing area with respect to all corrosion protection measures (it stated that it excluded 'onshore sections at any landfall of pipelines'). In the Australian context, this exclusion prompted the reapplication of AS 2885. These parts of AS2885 were not written with the shore crossing area in mind, meaning the corrosion protection measures may not have been ideal for this area, presenting a gap in the Standard.

The current version of DNV OS-F101, while providing guidance for corrosion mitigation on the shore crossing, does not provide specific guidance for cathodic protection of pipelines at the shore crossing. AS 2885 indicates that cathodic protection is not an applicable method for mitigating corrosion "above ground" but makes no comment on the shore crossing area.

5.2 *Standards from outside Australia*

The EN 15257:2006 Cathodic protection – competence levels and certification of cathodic protection personnel was approved by the European Committee for Standardization (CEN) on October 28th 2006. The standard was given the status of national standards in the European countries belonging to the CEN/CENELEC group in 2007. The standard defines three competence levels of personnel acting in the field of cathodic protection, including survey, design, installation, testing and maintenance. It specifies a framework of procedures for the training and certification for the personnel to reach and demonstrate the competence levels. It defines the minimum requirements for certification bodies responsible for this certification. The competence levels and certification schemes apply to each of the following application sectors:

- Underground and immersed metallic structures
- Marine metallic structures
- Reinforced concrete structures
- Inner surfaces of metallic container structures

The standard refers to the following EN standards dealing with cathodic protection:

EN 12743, 12474, 12495, 12499, 12696, 12954, 13173,13174, 13509, 13636, 14505, 15112, 50162, EN ISO/IEC 17024:2003, EN ISO 8044:1999, CEN/TS 14038-1.

The three levels of competence defined in the EN standard correspond to the U.S. agreed competence levels, developed by NACE International[156], which is the principal professional organisation for the development of corrosion control standards and test methods. NACE international has over 23,000 members worldwide and can be seen as the main authority for Oil & Gas Corrosion in the world. The European Federation of Corrosion has also a working party on Corrosion in the Oil and Gas industry and has published many books and guidelines on corrosion prevention and integrity management. In recent years NACE International and the

156 < http://web.nace.org/departments/education/Program.aspx?id=2ce9ffdb-8816-db11-953d-001438c08dca>

EFC have started to work closely together to harmonise international practice. The Australasian Corrosion Association has also adapted the NACE training and certification scheme for Cathodic Protection. Taking the above into account: Europe, USA, the Middle East (NACE strong hold) and Australia/New Zealand have adopted very similar training and certification schemes, the main difference being the different units used in the different regions.

NACE published recommended practice for many years, *e.g.*, RP-01-69 – Recommended Practice. Control of External Corrosion on Underground or Submerged Metallic Piping Systems. This RP was first published in 1969 and has been updated over the years; the latest version is the standard practice SP0169-2007 (updated 2007).

The ANSI/NACE Standard Practice SP0607-2007 has adopted the ISO 15589-2:2004 Petroleum and Natural Gas industries–Cathodic Protection of Pipeline Transportation Systems – part 2: Offshore pipelines. The ISO standard consists of 2 parts: Part 1: On land pipelines, and Part 2: Offshore pipelines. It should be noted that the EN standards are not very different to the ISO versions.

It is clearly stated that for the landfall, the ISO 15589-1 should be used. Furthermore, the following references taken from the document ISO 15589-2: off-shore installation state:

In the scope of this standard is written:

> *NOTE Special conditions sometimes exist where cathodic protection is ineffective or only partially effective. Such conditions can include elevated temperatures, disbonded coatings, thermal insulating coatings, shielding, bacterial attack, and unusual contaminants in the electrolyte.*

The standard states further in the section for CP system requirements:

> *Design, fabrication, installation, operation and maintenance of CP systems for offshore pipelines shall be carried out by experienced and qualified personnel.*
>
> *The CP system shall be designed with due regard to environmental conditions, neighbouring structures and other activities.*
>
> *Offshore pipelines that are protected by galvanic anode systems should be electrically isolated from other pipelines and structures that are protected by impressed-current systems. Offshore pipelines shall be isolated from other unprotected or less protected structures, which could drain current from the pipeline's CP system. If isolation is not practical or stray current problems are suspected, electrical continuity should be ensured.*

> *Care shall be taken to ensure that different CP systems of adjacent pipelines or structures are compatible and that no excessive current drains from one system into an adjacent system….*
>
> *… For the cathodic protection of short lengths of submarine pipelines and their branches that are directly connected to cathodically protected onshore pipelines, ISO 15589-1 shall be used.*

In the section design parameters:

> *The design of a pipeline CP system shall be based on detailed information on the pipeline to be protected, including material, length, wall thickness, outside diameter, pipe-laying procedures, route, laying conditions on the sea bottom, temperature profile (operating and shut in) along its whole length, type and thickness of corrosion-protective coating(s) for pipes and fittings, presence, type and thickness of thermal insulation, mechanical protection and/or weight coating,…..*
>
> *… - information on existing pipelines in close proximity to or crossing the new pipeline, including location, ownership and corrosion-control practices, information on existing CP systems (platforms, landfalls, etc.) and electrical pipeline isolation.*

In the section Protection parameter is stated that the use of intelligent pigs will indicate deficiencies in the corrosion protection.

> *…The effectiveness of CP or other external corrosion control measures can be confirmed by direct measurement of the pipeline potential. However, visual observations of progressive coating deterioration and/or corrosion, for example, are indicators of possible inadequate protection. Physical measurements of a loss of pipe wall thickness, using divers, or using internal inspection devices such as intelligent pigs, can also indicate deficiencies in the level of corrosion protection.*

ISO 15589-1:2003 specifies requirements and gives recommendations for the pre-installation surveys, design, materials, equipment, fabrication, installation, commissioning, operation, inspection and maintenance of cathodic protection systems for on-land pipelines, as defined in ISO 13623, for the petroleum and natural gas industries. ISO 15589-1:2003 is applicable to buried carbon steel and stainless steel pipelines on land. It can also apply to landfalls of offshore pipeline sections protected by onshore-based cathodic protection installations. ISO 15589-1:2003 is also applicable to retrofits, modifications and repairs made to existing pipeline systems.

In summary, standard practices in industry, documented by NACE International, ISO, ASTM and other bodies, point out the extra risk of external corrosion of pipelines at landfalls and that special precaution should be taken. Furthermore, it is today standard practice that personnel working with cathodic protection should be certified for the type of work they carry out on pipelines, be it a cathodic protection tester (testing the system), Technologist (testing and evaluating data to determine the effectiveness of the CP systems and to gather design data), Technologist (knowledge for trouble shooting and mitigation of problems) or specialist (CP-design). (EN 15257:2006 combines CP-Tester and Technologist to one level of certification).

6. Summary

The incident at Varanus Island on June 3rd 2008 could have been avoided if attention was paid to the inspection reports provided. Apache has continuously been working on the integrity management but the physical work of inspecting the pipelines on the beach crossing of Varanus Island has not been performed accordingly to the routines prescribed by Apache and its consultants. Reading through the different reports and procedures for inspections, it becomes clear that there was no or little effective communication on the subject of pipeline integrity and corrosion protection between the management and the operation. This raises questions about Apache's competence to maintain the SGL pipeline. It is also noted that the regulators have not taken notice on the discrepancy between inspection prescribed and inspection that has actually been performed. Last but not least, it is worth pointing out that several contracted inspections and reviews performed by consultants resulted in reports that did not raise a strong concern about the condition of the 12" SGL pipeline at the beach crossing of Varanus Island. It would require a corrosion engineer to pick up on some of the issues raised, but on the other hand, a consultant would expect an expert to read the reports.

7. Recommendations towards technical and safety aspects for future pipeline operation in Australia

a) In order to avoid/minimise the risk that such an incident on Varanus Island will be repeated, the following recommendations can be made: Undertake a comprehensive expert review of corrosion protection, CP systems and possible stray current and other interference on Varanus Island and remedy any shortcomings.

b) Improve communication between industry, consultants, educational institutes & research providers, engineering associations (EA, MA, ACA, SPE etc) and the government. Care has to be taken to find a good compromise between safety and costs. Working towards a risk based corrosion inspection system is the current trend in industry and it would be good to harmonise the individual efforts between the different Oil and Gas operators in Australia. This will require the harmonisation of standards on international level. However, Australia is not the only country facing these difficulties. Back in the 1960s a similar situation led to the establishment of a Royal Corrosion Committee in Sweden that took up the role as advisor to the legislation, best practices and education questions. This model has proven to be very successful, several ISO standard have been born from the work of that committee. This should also work in Australia.

c) Improve education of personnel at all levels in both government and industry:

   a. Adoption of the need for certification for CP-personnel, either according to the European Model or the US model (NACE International) moving towards a world-wide harmonisation in corrosion standards. Since most operators operate at international level, a harmonisation of standards would help everyone involved.

   b. Developing a state/federal approved Corrosion Engineering degree on request of the Australian Government. The cost of corrosion is between 3 to 4 per cent of the GDP, which translates to ca $66 billion lost every year (more than the predicted budgeted deficit for Australia 2009). About $6 billion could be saved through education in schools and universities. Ca $20 billion through applying today's knowledge in industry to minimise the waste of resources. (Study performed by the World Corrosion Organisation with the help of the Australasian Corrosion Association).

Woodside and Chevron have already made a start through the Western Australian Energy Research Alliance (WA:ERA) by funding the inaugural Chair in Corrosion Engineering at Curtin University of Technology. In the USA, the Department of Defence contracted Akron University to develop a Corrosion Engineering degree for the US, Curtin University of Technology, one of the WA:ERA partners, has started a collaboration with Akron. The cost of developing a similar degree for Australia would be small compared to the benefits and improved operational safety throughout the country, not only in the Oil & Gas Industry.

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Annex 6: Legislative framework for offshore and island petroleum activities

Following the 1979 Offshore Constitutional Settlement, the waters adjacent to Western Australia fall into three categories:

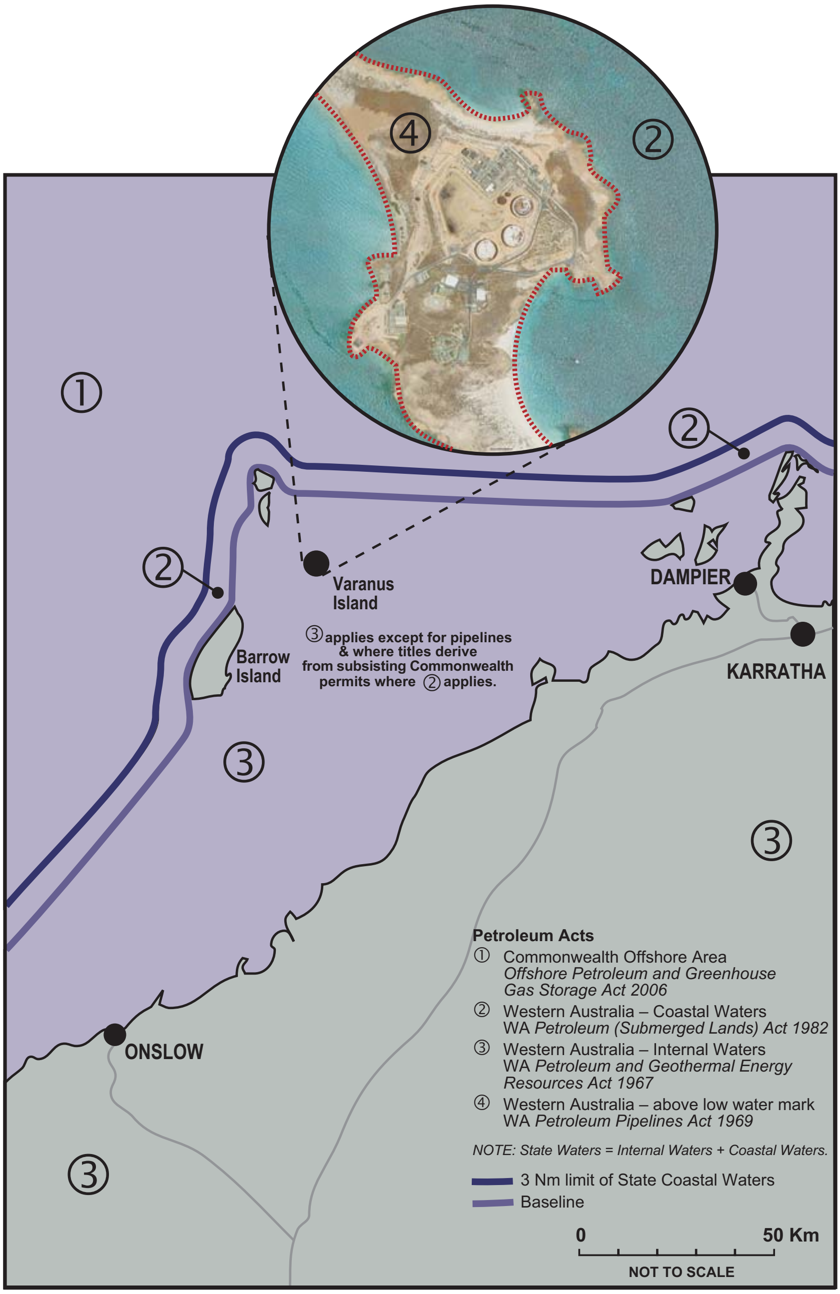
(a) *Commonwealth waters* – these are the waters covered by the *Commonwealth Offshore Petroleum and Greenhouse Gas Storage Act 2006*, i.e. waters of the continental shelf outside the 3 nautical mile territorial sea.

(b) *Designated coastal waters* of each State and the Northern Territory – these are the waters covered by the mainland State and Northern Territory *Petroleum (Submerged Lands) Acts*, i.e. the first 3 nautical miles of the territorial sea adjacent to each State and the Northern Territory, plus (in the case of Western Australia) some title areas landward of the territorial sea baseline but external to the mainland State. The latter areas originate from pre 1982 exploration permits issued under the Commonwealth PSLA, which formerly extended into those waters. Varanus Island, although classified as an onshore area, lies within the designated coastal waters. The WA *Petroleum (Submerged Lands) Act 1982* also covers all offshore pipelines in either the designated coastal waters, or the internal waters. This coverage extends from the mean low water mark (either on an island or the mainland) to the outer limit of the territorial sea.

(c) *Internal Waters* – waters landward of the territorial sea baseline (or inner limit of the territorial sea) but excluding the area referred to in (b) above.

Oil and gas resources and operations in Commonwealth waters are regulated by the *Commonwealth Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGSA). The Joint Authority, currently consisting of the Commonwealth Minister for Resources and Energy and the WA Minister for Mines and Petroleum, is responsible for making decisions regarding the areas to be opened

Figure 8: Varanus Island: relevant legislation boundaries



for applications for permits; the grant and renewal of exploration permits and production licences; approval of instruments creating interests in permits and licences; and the determination of permit or licence conditions governing the level of work or expenditure. In the event of a disagreement, the Commonwealth has the right of veto. Both Ministers have delegated the majority of their responsibilities as the Joint Authority under the OPGGSA to their relevant Departments. With the exception of safety issues, which are regulated by NOPSA, day to day administration of facilities in Commonwealth waters is undertaken by the WA Department of Mines and Petroleum (DMP).

Safety of oil and gas operations in Commonwealth waters is regulated by the National Offshore Petroleum Safety Authority (NOPSA), created under what is now the OPGGSA, and the *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996* (MOSOF Regulations). NOPSA commenced operations on 1 January 2005. NOPSA's responsibility is focussed on risk to human safety when personnel and hydrocarbons are present. If proposed changes to the MOSOF regulations (and possibly to the overarching Act), are drafted in 2009, NOPSA will also regulate the integrity of facilities (eg platforms, monopods and turret moorings) and pipelines.

Oil and gas resources and operations in WA designated coastal waters are regulated under the WA *Petroleum (Submerged Lands) Act 1982* (PSLA 82), which largely mirrors the Commonwealth OPGGSA in order to create a consistent regulatory environment. Day to day administration of non safety related matters is undertaken by DMP with powers delegated by the WA Minister for Mines and Petroleum. Safety in the WA designated coastal waters is the responsibility of NOPSA. In these waters, the Safety Authority's general functions and powers are derived from the WA *Petroleum (Submerged Lands) Act 1982* and its specific regulatory functions and powers are derived from provisions of that Act, and regulations made under it, that 'mirror' Schedule 3 and the Commonwealth occupational health and safety regulations. The WA NOPSA PSLA 82 amendments were passed in 2005 and commenced together with the required four safety regulations in March 2007. From March 2007 NOPSA has regulated petroleum safety in its own right in the WA designated coastal waters area.

Onshore oil and gas resources and operations are regulated primarily under the *Petroleum and Geothermal Energy Resources Act 1967 (*WA PGERA) which covers all onshore areas of the State, and, in certain circumstances, areas of internal waters. The WA PGERA contains no provisions for pipelines as this is provided for under the WA *Petroleum Pipelines Act 1969*. As noted above, the *Petroleum Pipelines Act 1969* only covers onshore areas, including the island production hubs (Barrow Island has its own legislation).

Until recently, in the internal waters under the WA PGERA and on the three island production hubs of Airlie, Thevenard and Varanus islands, NOPSA provided technical advice and auditing under a Service Agreement with WA. The Service Agreement set out a framework for the range of services and advice that could be provided. In practice, NOPSA would audit and assess safety and provide a report with recommendations to DMP's predecessor, the Department of Industry and Resources (DOIR), upon which DOIR then acted.

Varanus Island lies within the WA designated coastal waters which, as noted above, for petroleum safety purposes are regulated by NOPSA other than on the island. The facility on Varanus Island is a production hub licensed mainly as pipeline licence PL12 under the WA *Petroleum Pipelines Act 1969*. DOIR was responsible for regulating the safety and integrity of the facilities located on the island above the mean low water mark. For the period 1 January 2005 to 3 February 2009, NOPSA provided technical advice and auditing on the Varanus Island facilities. This has now passed to DMP.

Annex 7: Commonwealth/WA misunderstanding re Varanus Island up to the incident

Differences between Commonwealth and Western Australian departments in their understanding of the history and background to regulation of Varanus Island and two other islands in Western Australian waters could impact on consideration of this Investigations's key recommendations. While decisions should desirably be based on the current circumstances and recommendations outlined in our report, a shared understanding of the relevant history may assist. This Annex cites key public documents available to the panel but is written in the light of confidential documents from both jurisdictions. Of course, there may be other documents of which the inspectors are unaware.

As outlined in Annex 16 below, a March 2000 independent review of Australia's offshore petroleum safety arrangements reached the primary conclusion that:

> *the Australian legal and administrative framework, and the day to day application of this framework, for the regulation of health, safety and environment in the offshore petroleum industry is complicated and insufficient to ensure appropriate, effective and cost efficient regulation of the offshore petroleum industry ... Much would require improvement for the regime to deliver world-class safety practice.*

The 2000 review team said that there were too many Acts, directions and regulations, their boundaries were unclear and there were overlaps, and their interpretation and application was inconsistent. In response, with Commonwealth/State/NT Ministerial agreement, the Commonwealth coordinated consideration of recommendations and policy options with senior State/NT officials and in 2001 published *Future Arrangements for the Regulation of*

Offshore Petroleum Safety which proposed a new national offshore safety regulatory body.

As part of the process towards forming a new national offshore regulator, Commonwealth and State/NT Ministers of the Ministerial Council for Mineral and Petroleum Resources (MCMPR) on 4 March 2002 agreed nine principles for offshore industry regulation including that: 'A consistent national approach to offshore safety regulation in both Commonwealth and State/NT waters is essential for the most cost-effective delivery of safety outcomes in the offshore petroleum industry.'

The MCMPR meeting in Perth on 13 September 2002 was chaired by the Western Australian Minister and considered the reports of a steering committee and three working groups tasked to develop the arrangements the new national offshore safety authority and recommendations by senior officials. The meeting Communiqué stated that: 'The national offshore safety authority will be a single agency covering both Commonwealth and State coastal waters and will be accountable to the Commonwealth, State and NT ministers. ... A single authority will reduce the regulatory burden on industry operating across multiple jurisdictions.' Attachment A to the Communiqué stated: 'That the authority is set up so that it may, if jurisdictions wish to provide it with appropriate regulatory powers, undertake safety regulatory activities in other areas of State/NT jurisdiction.' Further it required: 'That effective and efficient coordination is established between the safety authority and other regulatory agencies.'

While it is clear that the new authority was to cover Commonwealth waters and the three nautical mile band of State/NT coastal waters, it was not agreed that it would cover 'internal' State waters and islands close to shore in WA. The Commonwealth/State/NT officials Steering Committee and its working Groups had supported the formation of a single statutory authority operating in both Commonwealth and coastal waters to the mean low water mark with powers conferred under Commonwealth and State/NT legislation. But this did not include waters within the limit of the State as at 1901 or islands within the limits of a state.

The next year, in 2003, a *National Offshore Petroleum Safety Authority Transition Plan* chaired by the Commonwealth included discussion of future service level agreements (SLAs) with the States/NT and stated:

> *There is agreement that the States and Northern Territory may contract for services for other areas (such as islands and offshore and onshore areas covered by State and Northern Territory petroleum acts). The proposed structure needs to be developed, with aspects to be addressed in such agreements to*

> *include delegation of powers, levels of authority and appropriate fee structures.*

The 2004 Commonwealth legislation that established NOPSA[157] emphasised occupational health and safety (OHS) and restricted the Authority's functions to offshore petroleum operations in Commonwealth waters and those conferred under State/NT Petroleum (Submerged Lands) Acts (or PSLA) in relation to designated coastal waters, plus cooperation with relevant States/NT. NOPSA's powers, including powers to enter into contracts, were linked to its offshore OHS functions. This suggests that NOPSA would not be able to contract to provide such regulatory services in State internal waters or on State islands. However, an additional section of the Commonwealth legislation (originally s150XI of the PSLA 1967 and then s360 of the OPA 2006 and now s650 of the OPGGSA 2006) allowed for a State or NT law (but not a contract) to empower NOPSA to exercise power in State internal waters or on islands in relation to offshore petroleum activity by a Constitutional corporation, if there is an agreement on fees payable, but stated that NOPSA and its staff are not obliged to do so. The original Explanatory Memorandum for the sub-section stated that it:

> *requires that there be an agreement between the Commonwealth and the State or Territory concerned as to the fees payable by the State or Territory for the exercise of powers by the Safety Authority or its staff/inspectors under onshore legislation. It is intended that there will be service level agreements, between the Commonwealth and the State or territory concerned, providing for the Authority's services to be made available.*

On 20 October 2004 there was a First and Second reading of the WA *Petroleum Legislation Amendment and Repeal Bill 2004* to insert a new schedule into the PSLA to cover NOPSA's proposed role in coastal waters, to repeal the *Petroleum Safety Act 1999* (which had not yet come into effect), and to provide for SLAs with NOPSA in internal waters and islands by invitation from WA on a case by case basis. The second reading speech reference to regulation onshore including islands that:

157 The Communiqué from the MCMPR meeting in Alice Springs from 29–30 July 2004 stated that NOPSA would become operational on 1 January 2005 and 'will deliver a uniform, high quality level of regulation of safety on offshore petroleum facilities in Commonwealth waters and State and Northern Territory coastal waters. NOPSA can also regulate onshore activities should the States/NT so choose.' While WA internal waters were not mentioned, the latter sentence appears to cover onshore islands such as Varanus, Airlie and Thevenard consistent with the WA position in 2002.

At present, the regulation of safety onshore relies on either ministerial notice – a direction; condition of licence; condition of approval; or by agreement with the operator. This is not only cumbersome but also potentially unreliable should steps in the notification and other processes be missed, rendering any non-observance of the safety rules free from prosecution. ... the public need to have confidence that such rules are enforceable.

This legislation lapsed due to a state election.

After the election, the *WA Petroleum Legislation Amendment and Repeal Bill 2005* was introduced, with minor amendments, on 7 April 2005. The 2005 second reading speech was substantially the same as on 20 October 2004 with the exception of the omission of the above quotation. Both versions included the following:

The commonwealth legislation also provides for the safety authority to undertake regulatory activities requested by a state in internal waters or onshore. If Western Australia made such a request, NOPSA would draw its powers from the state legislation. Those circumstances will be where the nature of the activity – for example, a pipeline extending from offshore to onshore – makes it appropriate for safety matters to be regulated by a single authority. It will, however, be on invitation by a state on a case-by-case basis and will be the subject of a service level agreement. In order for this latter provision to be enacted, it is beneficial to replicate the safety provisions of the commonwealth and the WA submerged lands acts in the Petroleum Act 1967 and the Petroleum Pipelines Act 1969 thereby avoiding NOPSA, petroleum companies and the work force from having to deal with a different style of safety rules.

However, while the Act received Royal Assent on 1 September 2005, the parts covering the *Petroleum Pipelines Act 1969* and the *Petroleum Act 1967* were still not proclaimed at the time of the 3 June 2008 incident.

In the event, the Commonwealth agreed to sign two service contracts with WA for NOPSA to provide services to the WA department with respect to (1) offshore petroleum operations in designated coastal waters; and (2) in internal waters and the three island production hubs of Airlie, Thevanard and Varanus. The former contract was meant to be short term pending the passage of the agreed amendments to the WA PSLA 1982, but these ultimately did not take place until March 2007 because of a range of factors, including various legislative resource constraints in WA[158]. Once enacted, the PSLA also became the vehicle for NOPSA to provide advice on various subsea pipelines regulated by WA.[159] The latter contract was also expected by the Commonwealth to be short term but, consistent with its longstanding position, WA seems only to have regarded it as short term in the sense of a longer term SLA contract being possible after it had amended the *Petroleum Act 1967* and the *Petroleum Pipelines Act 1969*.

The most recent NOPSA Services Contract was executed by senior officers of NOPSA and the WA Department of Industry and Resources (DOIR) on 26 June 2008 and has a term to 30 June 2010, with fees agreed on 8 July 2008 on behalf of the Commonwealth by the department Secretary. The contract recital provisions seem out of date in referring to NOPSA's initial legislation and stating that WA is to mirror Commonwealth legislation and confer powers upon NOPSA in relation to offshore petroleum operations in designated WA coastal waters (which had occurred in 2007). This reference to coastal waters appears now to mean internal waters and islands. The third recital states that: 'NOPSA has the power to enter into contracts and this Services Contract is to provide interim arrangements for the provision of services by NOPSA to the State until the above legislation and associated regulations are passed and take effect, and a new service level/delivery agreement is entered into between the State and NOPSA.' The contract scope is then stated to cover the provision of contractor services for the regulation of safety and health in relation to the now '*Petroleum and Geothermal Resources Act 1967* (coastal waters only) and the *Petroleum Pipelines Act 1969* (for pipeline licences on Varanus, Thevanard and Airlie Islands and other pipeline licences as may be nominated from time to time)'. The reference to 'coastal waters' seems to mean what had previously been termed 'internal waters'. Schedule B to the contract in relation to fees again refers to the previous Commonwealth legislation that set up NOPSA (section 150XI of the *Petroleum (Submerged Lands) Act 1967*) and to the fees being in relation to services in WA waters to which the PSLA

158 On 31 May 2007 the senior officers of NOPSA and DOIR executed a Memorandum of Understanding effective to 31 December 2012 which confirmed in schedule 1 that 'For non-PSLA waters all processes are a State responsibility'. It then outlined the allocation of respective petroleum regulatory duties involving the WA Designated Authority in designated coastal waters and the Joint Authority in Commonwealth waters and NOPSA with respect to tenement administration, drilling, development planning and construction and production, diving and decommissioning.

159 Including the Apache 12 inch SGL upon which NOPSA provided advice in March 2008 via the Pipeline Safety Management Plan element of the Pipeline Management Plan.

1982 does not apply and that are covered by parts of *Petroleum Act 1967* and the *Petroleum Pipelines Act 1969*, ie designated internal waters and islands.

Correspondence between the current Commonwealth and WA Ministers should be considered in the light of the foregoing. In summary, while WA was very slow to enact legislation to enable NOPSA to regulate in coastal waters and for all subsea pipelines, WA appears never to have decided or undertaken to do more than enact legislation/regulation that would facilitate longer term service contracts with NOPSA with respect to Varanus, Airlie and Thevenard Islands. However, WA has thus far not done this. The Commonwealth consistently wanted WA to provide for NOPSA having a longer term role in internal waters and islands consistent with other offshore petroleum regulation but did not advise WA clearly that NOPSA's legislation did not allow NOPSA to enter into contracts for the three islands in the absence of WA enabling laws. This contributed to the jurisdictional, legislative, and regulatory complexity and confusion. Our preferred recommendation is that WA and the Commonwealth reach agreement and legislate as soon as possible to give NOPSA coverage on the three islands and associated pipelines. If WA agrees, we believe that as an interim measure, it could be reconsidered (including in light of the 2005 WA legislation) whether relevant individual NOPSA inspectors and their supervisors could be appointed as inspectors under s62 of the *Petroleum Pipelines Act 1969* with fees to be agreed by the Commonwealth (s650(1) and (3) of OPGGSA).

Annex 8: Interfaces between DOIR & DOCEP, & DOIR & NOPSA

Interface with DOCEP

Prior to the creation of the National Offshore Petroleum Safety Authority (NOPSA) on 1 January 2005, responsibility for petroleum safety in both WA offshore and onshore sectors was the responsibility of the Safety and Environment Branch within the Petroleum Division of the Department of Industry and Resources (DOIR). During that same period, responsibility for occupational safety and health and environmental regulations across the mining sector was the responsibility of the Safety Health and Environment Division (SHED) of DOIR.

On 1 March 2005, the technical officers (petroleum inspectors) transferred to SHED, while the environmental officers transferred out of SHED and the division was renamed the Safety and Health Division (SHD).

Shortly thereafter, on 1 July 2005, SHD was transferred from DOIR to the Department of Consumer and Employment Protection (DOCEP) and renamed the Resources Safety Division (RSD). This resulted in further technical staff leaving the Petroleum Division (DOIR) to take up their new position at SHD at a time when around another eight technical staff members leaving for higher paying jobs within NOPSA. The RSD is responsible for administration of the:

- *Dangerous Goods Safety Act 2004*; and
- the *Mines Safety and Inspection Act 1998*.

The Minister for Resources, under his department i.e. DOIR, retained responsibility for the regulation of occupational safety and health under the *Petroleum and Geothermal Energy Resources Act 1967* (formerly the *Petroleum Act 1967*) and the *Petroleum Pipelines Act 1969* even though he had lost most of the technical petroleum safety expertise from DOIR. DOCEP was requested to carry out certain occupational safety and health regulatory functions for DOIR (since it had no staff to effectively undertake this function), and provided advice in relation to safety to DOIR, as specified and agreed in a Memorandum of Understanding (MOU) which was eventually signed on the 17 August 2007.

This MOU took some time to evolve as a number of issues arose in relation to which department had regulatory responsibilities and issues of which authority would cover the matter of pipeline and petroleum facility integrity. DOCEP had come to some agreement that it would provide advice on integrity matters to DOIR as requested of it.

Therefore, the scope of this MOU covered the provision of services by DOCEP in relation to the regulation of safety and health (including facility integrity) and the provision of technical advice and guidance to DOIR in relation to the following legislation:

- The *Petroleum Act 1967* (WA);
- The *Petroleum Pipelines Act 1969* (WA);
- The *Petroleum (Submerged Lands) Act 1982* (WA).

The scope of this Agreement specifically excluded those facilities and marine operations covered by these Acts for which regulatory services were provided by NOPSA under separate contractual agreement(s) with DOIR. In general, DOCEP provided these services to DOIR for onshore (mainland) areas including Barrow Island but not Varanus, Thevenard and Airlie islands.

The scope of the MOU also excluded marine seismic vessels and operations. It is also important to note that the responsibility for the administration of petroleum legislation and enforcement remained with DOIR.

On 1 January 2009, the Department of Mines and Petroleum (DMP) came into being and RSD transferred into the new department from DOCEP. The RSD now provide services to DMP as part of the organisational structure. The Petroleum and Royalties Division was renamed Petroleum and Environment Division.

Interface with NOPSA

NOPSA is the statutory authority which has the responsibility for administering and regulating occupational health and safety (OHS) matters on offshore petroleum facilities. NOPSA commenced operations on 1 January 2005 and has its headquarters in Perth.

Whilst NOPSA has assumed responsibility completely in Commonwealth waters, there has been a transitional period whereby NOPSA acted as contractor for DOIR with respect to the latter's responsibilities in WA State waters. On 16 December 2004, an MOU between NOPSA and the State was signed to take effect from the

1 January 2005 and continue in force until 31 January 2007. The MOU was subsequently extended to December 2012 (if required).

This MOU provided for the mutual intentions of both parties to ensure effective administration of the regulations under the *Petroleum (Submerged Lands) Act 1982* (WA) (PSLA). The MOU stated that all processes in non-PSLA waters were a State responsibility. The schedule to the MOU provided detail on the interface between NOPSA and the State (through its Designated Authority in coastal waters and Joint Authority in Commonwealth Waters) to allow proper exchange of information and the agreed position on areas of responsibility.

Service Contract No. 1 – PSLA

On 30 December 2004, the first service contract between the State and NOPSA was signed to provide interim arrangements for the provision of services by NOPSA to the State until the PSLA legislation and associated enabling regulations were passed and took affect. The contract took effect from 1 January 2005 and remained in force until 30 June 2005 or sooner if the amendments to the PSLA to confer functions upon NOPSA in relation to offshore petroleum operations in the designated coastal waters of the State came into effect prior to this date.

The contract allowed for a monthly fee for services and a schedule which provided details regarding the provision of technical advice and services to DOIR for the contract areas in respect to assessments (including evaluation of safety case submissions), audits and inspections (against the safety cases, PMP, Diving SMS or Project plans), investigations (for safety incidents), advice, resolution of issues, enforcement/prosecutions (recommendations to DOIR) and consultation.

The responsibility for OHS under the Act remained with DOIR during this period and NOPSA did not purport to exercise any power or to perform any function under any law of the State. This contract was purely a service to DOIR to assist it to perform its functions under the PSLA until NOPSA received the conferred powers.

Part 4 of the WA *Petroleum Legislation Amendment and Repeal Act 2005* (PLAR Act 2005) covered the OHS provisions of the PSLA i.e. safety regulations covering diving safety, pipeline management and OHS on offshore facilities.

With the commencement of part 4 of the PLAR Act 2005 on 27 March 2007, NOPSA was enabled to operate in its own right in WA coastal waters under the PSLA rather than under the service contract. This service contract consequently lapsed at this time.

Service Contract No. 2 – *Petroleum Act 1967* (WA) and *Petroleum Pipelines Act 1969* (WA)

On 13 January 2005, a services contract between the State and NOPSA was signed to cover the provision of contractor services for OHS in relation to:

- the *Petroleum (and Geothermal Energy Resources) Act 1967* (WA) (coastal waters only); and
- the *Petroleum Pipelines Act 1969* (WA) (for pipeline licences on Varanus, Thevenard and Ailie Islands and other pipelines that can be nominated from time to time).

This contract provided for NOPSA and its staff to conduct services as contractor to DOIR in relation to the above legislation in WA in waters of the seas that are landward of the baseline of Australia's territorial sea adjacent to the State that are not waters to which the PSLA apply or within the limits of the State. NOPSA itself did not have regulatory powers in these areas.

NOPSA provided technical advice and contractor services to DOIR for the above areas with respect to assessments (safety case submissions, review of technical reports etc), audits and inspections, investigations, advice, resolution of issues, enforcement, prosecutions and appeals (issuing of improvement and prohibition notices etc), and consultation with operators.

DOIR maintained the role of appointing inspectors for the purposes as specified in this service contract and remained the regulator for OHS and integrity. NOPSA staff did not take up the option to be appointed inspectors during the course of this contract (and its renewals) as legal advice precluded them from doing so.

Subsequent renewals were eventually extended from 3 monthly to yearly with the last renewal being for a 2 year period until NOPSA ceased providing such services in February 2009, with the exception of some support services with respect to the Varanus Island reinstatement works.

Annex 9: Apache's documentary responses to regulatory requirements for pipeline licence PL12 and safety cases

This annex describes and documents Pipeline Licence 12 (PL12) and its variations including a safety case requirement[160] under the WA *Petroleum Pipelines Act 1969* from 1998. It also documents other offshore safety case requirements under what is now the *Commonwealth Offshore Petroleum and Greenhouse Gas Storage Act 2006* and Petroleum (Submerged Lands) (Management of Safety in Offshore Facilities) Regulations 1996. Finally, it documents a pipeline safety management plan, which amounts to a safety case as part of a Pipeline Management Plan phased in under the WA *Petroleum (Submerged Lands) Act 1982* through the WA *Petroleum (Submerged Lands) (Pipeline) Regulations 2007*.

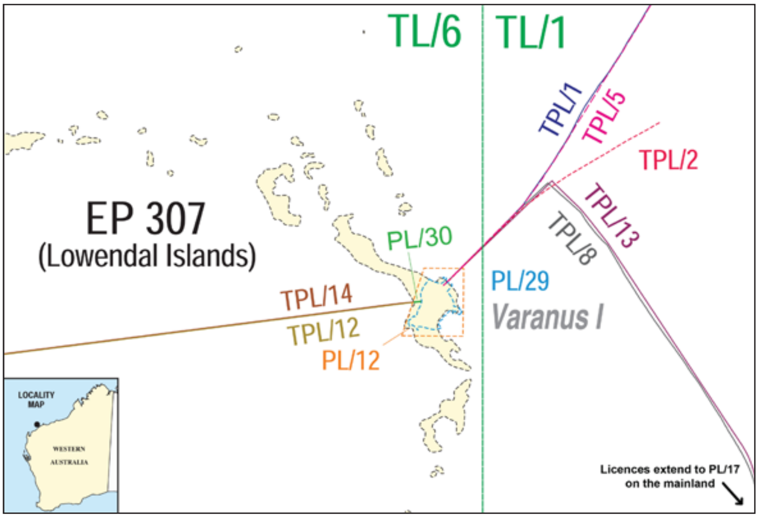
While under legislation designed for pipelines, the PL12 licence covers most of the Varanus Island hub for collecting and processing upstream oil and gas. The PL12 licence also includes the 12 inch and 16 inch SGLs as they leave Varanus Island and down to the limits of the licence as they begin (subsea) to make their way to the mainland. This includes the shore crossing section of the 12 inch pipeline which first ruptured on 3 June 2008. Although the facilities encompassed by PL12 include a small offshore area, most of the offshore section of the 12 inch SGL is covered by Licence TPL 8. Most of the offshore section of the 16 inch SGL is covered by Licence TPL 13. The two pipelines are an average of 9 m apart for the 70 km subsea section. Both offshore licences were issued

160 A description of the evolution over time of the conditions on the licence, amended by subsequent variations can also be found in chapter 3.

more recently than PL12, and under the authority of more recent legislation. When the pipelines reach the mainland, they are both covered by Pipeline Licence PL17 for about 30 km. The 12 inch SGL is therefore about 100 km long and stretches from the pig launcher at the plant on Varanus Island to the pig receiver on the WA mainland at Compressor Station 1 before the pipe joins the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

The context of PL12

Figure 14: Varanus hub pipeline licences



Almost all the Varanus Island facility operated under Pipeline Licence PL12. This licence was originally issued on 9 May 1985 to Bond Corporation Pty Limited, Bond Oil Pty Ltd, Texas Eastern Australian Inc, Reading & Bates Australia Petroleum Co, Pontoon Oil & Minerals NL, Pelsart Oil NL and Swan Television & Radio Broadcasters Limited. Texas Eastern Australian Inc was replaced later in 1985 by Texas Eastern Australia Development Pty Ltd, which was a minority shareholder in the joint venture. The WA regulator's files show that on 18 November 1988, Texas Eastern Australia Development Pty Ltd changed its name to Hadson Australia Development Pty Ltd. On 8 December 1994 Hadson Australia Development Pty Ltd registered a name change with ASIC to Apache Northwest Pty Ltd, which was recorded with the WA regulator on 29 December 1994. These changes reflected a change of ownership. Pipeline licence PL12 was valid for 21 years. Four separate variations had been applied to PL12 before Apache Northwest took over, and 13 variations have been sought by Apache and applied since then. The

Current title holders are Apache Northwest Pty Ltd 68.5 per cent, Kufpec Australia Pty Ltd 19.2771 per cent, and Tap (Harriet) Pty Ltd 12.2229 per cent. Apache Northwest Pty Ltd is the current Title and Pipeline Operator.

Seq	Variation number	Issue date	Facility and plant description
1st	PL12 Var. No. 1/88-91	21-Oct-88	Harriet 6˝ Gas Export
1st	PL12 Var. No. 1/88-91	21-Oct-88	Varanus Island Ground Flare
1st	PL12 Var. No. 1/88-91	21-Oct-88	Varanus Island LPG Plant (The proposal to install LPG plant was subsequently withdrawn)
1st	PL12 Var. No. 1/88-91	21-Oct-88	Varanus Island Rosette Separators
1st	PL12 Var. No. 1/88-91	21-Oct-88	Varanus Island Loading Facilities
2nd	PL12 Var. No. 1/91-2	11-May-92	Campbell-Sinbad-Linda 12˝ CA Gas Export Onshore Pipeline
2nd	PL12 Var. No. 1/91-2	11-May-92	Harriet 6˝ Gas Export
2nd	PL12 Var. No. 1/91-2	11-May-92	Sales Gas Lines 12˝ Gas Export
3rd	PL12 Var. No. 1/92-3	01-Jun-93	Varanus Island Tanami No 1 Wellhead Production Facilities
4th	PL12 Var. No. 2/94-5	14-Nov-94	Varanus Island 3-Phase Flowline from Alkimos 1 Wellhead to Rosette Separator
5th	PL12 Var. No. 4/94-5	06-Jun-95	Varanus Island Dehydration Unit
5th	PL12 Var. No. 4/94-5	06-Jun-95	Varanus Island Depropaniser / Reboiler / Condenser (Train 1)
5th	PL12 Var. No. 4/94-5	06-Jun-95	Varanus Island Turbo-Expander (Train 1)
5th	PL12 Var. No. 4/94-5	06-Jun-95	Varanus Island Sales Gas Compressors
6th	PL12 Var. No. 2/95-6	11-Aug-95	Varanus Island Civil Works in preparation for East Spar
7th	PL12 Var. No. 4P/96-7	12-May-97	Varanus Island Agincourt Separators
7th	PL12 Var. No. 4P/96-7	12-May-97	Varanus Island Agincourt Flash Gas Compressor
7th	PL12 Var. No. 4P/96-7	12-May-97	Varanus Island Agincourt Hot Oil Heater
7th	PL12 Var. No. 4P/96-7	12-May-97	Varanus Island Agincourt Heat Exchanger
7th	PL12 Var. No. 4P/96-7	12-May-97	Varanus Island Agincourt Product and Produced Water Pumps
7th	PL12 Var. No. 4P/96-7	12-May-97	Varanus Island Agincourt Pipeline Pig Receiver
7th	PL12 Var. No, 4P/96-7	12-May-97	Varanus Island Agincourt Gas Engine Powered Reciprocating Gas Compressor
8th	PL12 Var. No. 9P/97-8	30-Sep-98	Sales Gas Lines 16˝ Gas Export
9th	PL12 Var. No. 13P/97-8	30-Dec-98	Wonnich 8˝ Gas Export No. 1
9th	PL12 Var. No. 13P/97-8	30-Dec-98	Wonnich 8˝ Gas Export No. 2

Seq	Variation number	Issue date	Facility and plant description
10th	PL12 Var. No. 7P/99-0	08-Aug-00	Varanus Island Process Control and Field Support Building
11th	PL12 Var. No. 2P/00-1	21-Sep-00	Varanus Island Amenities Building Extensions
11th	PL12 Var. No. 2P/00-1	21-Sep-00	Varanus island Laundry
11th	PL12 Var. No. 2P/00-1	21-Sep-00	Varanus Island Accommodation Unit
11th	PL12 Var. No. 2P/00-1	21-Sep-00	Varanus Island Helicopter Services Building
11th	PL12 Var. No. 2P/00-1	21-Sep-00	Varanus Island Reverse Osmosis Potable Water Generating Unit
12th	PL12 Var. No. 5P/00-1	27-Mar-01	Varanus island Flare Knock-Out Drum
12th	PL12 Var. No. 5P/00-1	27-Mar-01	Varanus Island Elevated Flare
12th	PL12 Var. No. 5P/00-1	27-Mar-01	Varanus Island Flare associated Valving, Fittings, Instrumentation and Equipment
13th	PL12 Var. No. 8P/00-1	04-Oct-01	Varanus Island Power Generation Plant, Equipment Room and Associated Controls
13th	PL12 Var. No. 8P/00-1	04-Oct-01	Varanus Island Instrument Workshop Facility
13th	PL12 Var. No. 8P/00-1	04-Oct-01	Varanus Island Fabrication and Welding Shop
14th	PL12 Var. No. 9P/00-1	26-Oct-01	Simpson 18″ Production Pipeline
14th	PL12 Var. No. 9P/00-1	26-Oct-01	Simpson 8″ Gas Lift Pipeline
14th	PL12 Var. No. 9P/00-1	26-Oct-01	Simpson 8″ Water Disposal Pipeline
14th	PL12 Var. No. 9P/00-1	26-Oct-01	Varanus Island Simpson Separation Facilities
14th	PL12 Var. No. 9P/00-1	26-Oct-01	Varanus Island Simpson Interim Gas Compression Facilities
14th	PL12 Var. No. 9P/00-1	26-Oct-01	Varanus Island Simpson Gas Turbine Compression Facilities
15th	PL12 Var. No. 1P/03-04	16-Dec-03	Rosette Disposal Well
15th	PL12 Var. No. 1P/03-04	16-Dec-03	Varanus Island Gas Processing Facilities
16th	PL12 Var. No. 4P/05-6	12-Sep-05	String of Pearls HJV valve Station to V1A/ V1B HJV Separators
17th	PL12 Var. No. 10P/05-6	01-Sep-06	HJV Oil Gathering System Upgrade

The foregoing material is extracted from WA Department files. Pipeline Licence PL12 formally expired on 8 May 2006 and an application to renew the pipeline licence was lodged as application 1P/05-6 in December 2005. Once an application is lodged, licences continue to operate pending a decision on their renewal.

Conditions applied to the original licence specified minimum standards for the licensee to maintain, however the conditions were regularly updated with licence variations. The operator's response to new conditions applied through variations has often been to incorporate those processes throughout the Varanus Hub although Apache believed the new conditions applied only to the newly licenced facilities.

Requirements for the use of accepted safety cases

Pipeline Licence PL12 was issued under the authority of the WA *Petroleum Pipelines Act 1969*, and directions pursuant to the Act. A requirement for a Safety Case for the facilities and pipelines covered by PL12 was first introduced for construction and operation of a variation on Varanus Island with licence variation 9P/97-8, issued 30 September 1998. The State regulator reported that prior to the creation of NOPSA on 1 January 2005, Commonwealth guidance notes on safety case design were supplied for operators who were required to provide a Safety Case.

In contrast, the detailed requirements for a Safety Case for all offshore operations associated with the Varanus Hub are found in the *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996* (MOSOF Regulations), which provide thorough detail on the subject matters to be covered in the safety case.

Apache adopted it own process entitled 'Varanus Island Operation Safety Case' from 2000, and the WA regulator accepted the Varanus Hub Safety Case on 22 July 2002. The Safety Case underwent a five-year review in 2007, and the offshore section was accepted by NOPSA on 31 October 2007 and the onshore section including Varanus Island itself was accepted by the regulator in the WA department (DOIR) on 6 December 2007.

Requirements for the use of an accepted Pipeline Management Plan

A Pipeline Management Plan (PMP) is required under the WA *Petroleum (Submerged Lands) (Pipeline) Regulations 2007*. A PMP must be submitted to the Designated Authority, who must then give a copy of the PMP to the Safety Authority. The Safety Authority considers the pipeline safety management plan (PSMP – those components of the PMP that provide for the health and safety of persons at or near the pipeline). The Designated Authority then accepts the PMP if: the Safety Authority accepts the PSMP; if there are reasonable grounds for believing that the plan is appropriate for the nature and proposed use of the pipeline; and if it complies with all relevant regulations.

NOPSA accepted the safety elements of Apache's Operational Pipeline Management Plan in March 2008. DOIR accepted the overall plan on 28 March 2008.

Apache documents

The investigation has reviewed safety-related documentation generated by Apache Energy Ltd or Apache Northwest Pty Ltd or by contractors on Apache's behalf that has been provided from a range of sources including the public domain. The documents most relevant to the
PL12 licence and safety cases include:

- Hadson Energy Ltd. Installation of subsea gas pipelines for gas-gathering scheme, marine monitoring programme, dated 20 December 1991
- Apache Statutory Inspection manual, dated 11 September 1996
- 12″/16″ Sales Gas Lines Offshore Section Risk Assessment by Stratex Pty Ltd, dated 11 August 1998
- Corrosion Risk Assessment and Inspection Scheme, by QCL International, dated September 1998
- Intelligent Pigging Procedure, Inspection and Reporting, dated 14 September 1999
- Production Facilities Integrity Corrosion Management Strategy, dated 24 February 2000
- CorrPro DCVG Survey, dated 3 December 2000
- JP Kenny, Shallow Water Pipelines Span Assessment, dated June 2000

- Varanus Island Formal Safety Assessment Attachment Report, by International Risk Consultants, dated 6 July 2001.
- Cathodic protection Survey of 12″/16″ Sales Gas pipelines by Auscor Pty Ltd, dated June 2002
- Cathodic protection Survey of 12″/16″ Sales Gas pipelines by Auscor Pty Ltd, dated July 2003
- Review of Apache Energy Pipelines by QCL International, dated 6 February 2004
- Shallow Water Inspection Program, dated 6 May 2004
- Offshore Pipelines Cathodic Protection Survey by Auscor Pty Ltd, dated August 2004
- Netlink Inspection Services, Ultra Shallow Water and Onshore Pipeline Inspection 15–19 October 2004, dated 30 November 2004
- Ionik Consulting, 2004 Level 1 Freespan Assessment, dated November 2004
- Ionik Consulting, 2005 Level 1 Freespan Assessment, dated April 2005
- 2005 Annual summary report of inspection and corrosion, dated 4 Jan 2006
- Onshore Pipeline Inspection Manual, dated 22 March 2006
- Fugro Survey Pty Ltd, Report for the Post Cyclone ROV Inspection, 29 May 2006
- Lloyd's Register PL12 independent validation, audit checklist, dated May 2006
- Operational reference document listing for the Lloyd's Register PL12 independent validation, including their scope and revision status, dated May 2006
- Initial Lloyd's Register PL12 validation plan, dated 26 May 2006
- Lloyd's Register PL12 independent validation, report on stage 1, dated 31 May 2006
- Lloyd's Register PL12 independent validation, report from first On Site integrity review (part of Stage 2), 12–14 June 2006, dated 30 June 2006
- Lloyd's Register PL12 amended validation plan, dated 8 August 2006
- Integrity Policy, signed August 2006
- Lloyd's Register report of On Site process integrity review, 3–7 August 2006, dated 21 August 2006

- Lloyd's Register Process Integrity Review, 28 September – 20 October, dated 20 December 2006
- Auscor Pty Ltd, Summary of Survey inspections and works yr 2000–2006, undated
- Review of recommendations from 2004 pipelines risk assessments by Moduspec Pty Ltd, dated 10 April 2007
- Gap Analysis Review of Apache Energy Pipelines by Moduspec, dated 10 April 2007
- Lloyds Register PL12 independent validation summary report, dated 10 May 2007
- Subsea Developments Sales Gas Pipelines 5-year Integrity Review, dated 30 May 2007
- Safety Management System description, Varanus Hub Supplement, Dated June 2007
- Safety Case for Varanus Hub, dated June–July 2007
- Apache Onshore pipeline inspection workbook, dated September 2007
- Corrosion Management System. Coating inspection procedure, dated 27 September 2007
- Varanus Hub safety case update, AE-91-RF-010.01A Rev 11, dated 5 October 2007
- Integrity Management Personnel and Competencies Description, dated 24 Jan 2008
- Cathodic Protection Annual Survey 2007 of 12″/16″ Sales Gas pipelines onshore section by Auscor Pty Ltd, dated March 2008
- Operational Pipeline Management Plan, by Ionik Consulting, dated March 2008
- Submission to Productivity Commission review of the regulatory burden on the upstream petroleum sector, dated September 2008
- ALERT/Burgoynes Varanus Island Facility Incident Report, dated September 2008.

Files held on file by the WA Department DOIR (now DMP)

DOIR retained many files covering the administration of PL12 which were examined by the inquiry. The most recent and relevant files are:

File number	File title
H0191/200803	PL12 licence renewal assessment report
H0243/200502	PL12 Apache Energy Ltd Vol 12
H0243/200501	PL12 Apache Energy Ltd Vol 11
03100/200301	Varanus Island Gas Expansion project PL12 Safety Case

Department of Employment and Consumer Protection (DOCEP)

DOCEP has been responsible for the safety and integrity regulation under a Memorandum of Understanding between itself and DOIR, of the mainland section of the 12 inch SGL from the mainland shore crossing to its termination at Compressor Station 1 (CS1) under pipeline licence PL17. DOCEP provided electronic files relating to its input in seeking a pipeline integrity review from the operator as required under the conditions of PL17, and to its efforts in ensuring the review met its expectations. DOCEP also provided other files to the Investigation

National Offshore Petroleum Safety Authority (NOPSA)

NOPSA provided electronic copies of its files of records provided to DOIR under the service contract between DOIR and NOPSA that related to its audits of facilities covered under PL12, and of its audits of the offshore facilities associated with the Varanus hub.

NOPSA provided information on the Pipeline Safety Management Plan (PSMP) the hub Safety Case, relevant audits, and a range of other material sought by the Inquiry.

Apache

While Apache did not readily provide us with access to most of its relevant documentation, we have reviewed the files held by the three regulators, and accessed a much more extensive range of Apache documentation compelled under s63 of the PPA.

Annex 10: Pipeline corrosion basics

A November 2008 78-page report by Dr Raymond Fessler written for the US Office of Pipeline Safety within the onshore pipeline regulator, PHMSA effectively provides a primer and layperson's summary of technical issues surrounding pipeline corrosion.

The report's introduction notes that:

> *The most important factors that complicate the investigation and/or mitigation of corrosion include the following:*
>
> - *The chemical properties of the environment surrounding a buried pipeline are not adequately understood.*
> - *Variations in the oxygen content, moisture content, and chemical composition of the soil along the pipe length and from top to bottom of the pipe can act as concentration cells that promote corrosion.*
> - *Moisture content and oxygen content of the soil also vary with time.*
> - *Coating quality varies along the length of a pipeline.*
> - *Coatings sometimes become disbonded from the pipe surface, allowing groundwater to contact the steel but shielding the steel from cathodic-protection currents.*
> - *Disbonded coating will prevent aboveground survey detection of underlying corrosive conditions.*
> - *Physical variations in soil characteristics and placement (gaps etc) affect the distribution of cathodic-protection current.*
> - *Visual inspection of the outside of the pipe and the coating requires evacuation.*
> - *Stray currents from nearby buried structures can interfere with a pipeline's cathodic-protection system.*

Fessler states further that:

> *corrosion is one of the major causes of pipeline failures … On average there has been 52 significant corrosion incidents per year in the US …77 per cent of the onshore incidents were due to external corrosion … Europe has experienced a slightly lower proportion of corrosion failures … high salt contents tend to increase corrosivity … bacteria can promote external corrosion*
>
> *… One of the main factors that influence a rate of external corrosion is the differences in the characteristics of the soil from place to place along a pipeline, as well as from top to bottom. Differences in aeration, moisture content, and soil composition in these areas can produce strong driving forces for corrosion … the two most importance factors in reducing or preventing the development of external corrosion on a pipeline are the level of cathodic protection and the quality of the pipeline coating … Corrosion problems can arise if the coating becomes disbonded from the pipe and allows groundwater to contact the steel pipe but shields that portion of the pipeline from the cathodic-protection currents.*

Based on risk:

> *To assess the structural integrity of a pipeline that may contact corrosion defects … [under US legislation there are] three acceptable approaches: In-line inspection [ILI includes three types of intelligent pigging], Hydrostatic testing, Direct Assessment … pipe-to-soil readings for cathodically protected pipeline systems must be taken annually at all test stations.*

Other expert sources accessed by the panel have emphasised the importance of considering pipes in a common easement holistically for the purposes of cathodic protection and ensuring multiple test points at vulnerable areas like shore crossings (see also Annex 23).

Annex 11: NTSB and TSB investigation reports on gas pipeline explosions involving external corrosion and CSB petroloeum refinery reports

The US National Transportation Safety Board (NTSB) and the Transportation Safety Board of Canada (TSB) are independent multi-modal safety investigation bodies like the Australian Transport Safety Bureau (ATSB). But unlike the ATSB, they each have federal powers to investigate, on their own initiative, serious pipeline accidents and incidents anywhere within the US and Canada respectively. There are several final investigation reports by both bodies that are relevant to this investigation. In addition, because the NTSB and TSB investigate only for future safety purposes (any regulatory or police investigation that may lead to fines or prosecution is separate), operators and others involved in accidents typically provide good cooperation. In contrast, in those jurisdictions where the regulatory body carries out the investigation, operators may wish (or be advised) to withhold material from other investigations and inquiries that may use it against them in future liability proceedings. In the US, the Chemical Safety and Hazard Investigation Board (CSB) uses a similar methodology separate from the regulator to investigate chemical industry accidents and incidents including oil refineries. This independent 'no-blame' systemic safety investigation model helps to uncover occurrence causality in complex high technology industries where organisational and regulatory factors may be as important or more important root causes or contributory factors.

NTSB investigations

On 24 August 1996, there was a pipeline rupture, liquid butane release and fire at Lively in Texas. The NTSB investigation (report PB98-916503) determined 'the probable cause of the accident was the failure of Koch to adequately protect its pipeline from corrosion'. A major safety issue was the 'adequacy of Koch's corrosion inspection and mitigation actions'. The 8-inch-diameter steel LPG pipeline originally constructed in 1981 had several hydrostatic pressure test failures before a May 1995 'smart pig' metal-wall-loss inspection was performed using a low-resolution magnetic-flux-leakage (MFL) internal inspection tool. After the accident, a high-resolution MFL inspection found severe corrosion in 15 lengths of pipe not identified 16 months previously, as rapid corrosion had occurred in the interim. The line had an external coating, before it was buried, to prevent corrosion. Corrosion was also mitigated by an impressed current cathodic protection system and the pipeline was subject to annual testing for external corrosion to comply with US regulation 49 CFR 195.416(a). Before the accident there had been a number of readings less than the industry norm of -0.85V. After the accident, readings 500 feet north and south of the rupture ranged from -0.49V to -0.52V. Significant corrosion was found at the centre of the pipe rupture, and while most anti-corrosion coating was destroyed in the fire, nearby pipe had experienced disbonding that significantly reduced cathodic protection via local shielding and had corrosion damage from 30 per cent to 64 per cent of wall thickness. A post-accident consultant found several types of bacteria with 'Aerobic Acid Producing bacteria ... the main contributor to the corrosion'. However, the testing was performed late about 48 hours after the pipe was removed from the ground, and the pipe was also cleaned by Koch and tap water was used for sample preparation instead of the phosphate-buffered saline solution recommended in NACE International Standard TM 0194-94. The NTSB discounted the result, stating that NACE International should develop a standard for microbial sampling and testing of external surfaces on an underground pipeline.

The NTSB found that despite a 1986 NTSB recommendation, regulation in Title 49 CFR 195.416 did not provide specific criteria for 'adequate cathodic protection' for liquid pipelines. There were specific criteria in appendix D of the gas pipeline safety regulations, 49 CFR 192. The NTSB was also concerned that 'because no overall requirement exists for operators to evaluate pipeline coating condition, problems similar to those that occurred on Koch's pipeline could occur on other pipelines' and recommended further revision by the regulator to 49 CFR Part 195.

On 19 August 2000 a 30-inch-diameter natural gas transmission pipeline operated by El Paso ruptured near Carlsbad, New Mexico with 12 people killed in addition to physical damage. The NTSB's probable cause 'was a significant reduction in pipe wall thickness due to severe internal corrosion' because the operator's 'corrosion control program failed to prevent, detect, or control internal corrosion'. There were also major safety issues with 'the adequacy of Federal safety regulations for natural gas pipelines, and the adequacy of Federal oversight of the pipeline operator'. While this was an instance of internal and not external corrosion, there were issues with both salt and bacteria in leading to corrosion and non-use of pigging or corrosion coupons or adequate monitoring devices. The NTSB noted that the regulator had published a notice of proposed rulemaking (NPRM) in January 2003 'to require operators of gas transmission pipelines to establish integrity management programs to identify and evaluate the condition of and threats to their pipelines in high-consequence areas and to take steps to protect against pipeline failures'. Also cited were American Society for Mechanical Engineers (ASME) publications on gas pipelines including managing system integrity and determining the threat of corrosion.

TSB investigations

On 29 July 1995 an initial rupture and fire occurred on the 42-inch TransCanada natural gas pipeline near Rapid City, Manitoba as a result of external stress corrosion cracking (SCC). The heat from this fire and delay in shutting down the line, led less than an hour later to a second rupture and fire on the adjacent 36-inch natural gas pipeline. The TSB referred to issues with polyethelene tape and asphaltic coatings susceptibility to SCC under specific environmental conditions and past TSB reports dealing with SCC in the soil types at the accident site despite cathodic protection. At the rupture site, polyethelene tape was used which is known to disbond and/or degenerate creating an area on the surface of the pipe which is shielded from the CP system. CP potentials at the rupture site exceeded minimum industry norms. The TSB noted that bacteria in the soil and groundwater act to accelerate the process of SCC. The operator's mitigation program included defining likely sites for SCC, hydrostatic testing and selective excavation, and identifying and removing 'significant' pipeline defects but had not prevented this rupture which occurred after a corrosion flaw extended 81 per cent into the pipe wall before the site had been excavated. The spacing of four pipelines in the 66.1 m right of way was generally 9.1 m but at the rupture site, two pipes were 7 m apart which was less than the company's horizontal standard (itself fairly common in the industry).

The TSB was critical of the lack of federal regulations for horizontal spacing, especially as there were vertical spacing standards.

On 27 February 1996 a rupture occurred on an Interprovincial 864 mm outside diameter pipeline built to carry crude oil. The failure was caused by 'excessive narrow, axial, external corrosion located adjacent and running parallel to the longitudinal seam weld of the pipe, which was assisted by low-pH stress corrosion cracking and was not identified through the company's ongoing pipeline integrity program called the Susceptibility Investigation Action Plan'. Annual pipe-to-soil surveys of the CP system were undertaken 'to ensure the existing minimum industrial norm of 850 millivolts (mV) 'off' cathodic potential and 100 mV shift potential were met'. Poor bonding of the tape wrap correlated with the corrosion at the centre of the failure. The TSB was 'concerned about the absence of programs to mitigate the risks presented by the consequences of disbondment of self-adhesive coatings on other pipeline systems ... making the pipeline system susceptible to general corrosion'.

On 2 December 1997 a rupture and fire occurred at an area of general external corrosion on the TransCanada 914 mm outside diameter natural gas pipeline near Cabri, Saskatchewan. There were six parallel pipelines in the vicinity. About 70 per cent of the wall thickness had been corroded after the pipe coating of asphalt enamel, felt wrap, kraft wrap and an outerwrap had either been damaged or become disbonded. The TSB stated that even a brief interruption in cathodic protection would have allowed corrosion at uncoated locations. Further 'since the soil conditions at the rupture site alternated between wet and dry, depending on the season, sections of the pipe that were poorly coated would have experienced variations in corrosion rates and the amount of current required for adequate protection'.

On 7 August 2000 there was a rupture in Westcoast Energy's 762 mm natural gas pipeline in British Colunbia. Surveys in 1995, 1997 and 1998 indicated lower than industry standard CP current reaching the ruptured section of pipe. Shallow surface pitting corrosion coincident with an area of higher pipe hardness on the surface of the pipe helped initiate a crack which later led to the rupture at an operating pressure of about 5599 kPa (6453 kPa was allowable).

On 14 April 2002 there was a rupture and fire in TransCanada's 914 mm diameter natural gas pipeline near Brookdale, Manitoba at a zone of stress corrosion cracking (SCC) initiated on the outside of the pipe that had progressed transgranularly through the grain structure rather than between the grain boundaries. The presence of minor corrosion pits was indicative that the CP was locally ineffective for some time allowing the SCC. Overall, the exterior hot-applied asphalt coating appeared to adhere well to the pipe but there were thin areas and disbonded areas. It found that 'the combination of a disbonded exterior coating, fluctuations in the environmental conditions surrounding the pipe, the presence of anaerobic bacteria, a susceptible high-strength steel pipe, and the existence of atomic hydrogen, probably from the cathodic protection reaction, together with a sustained tensile stress due to the internal operating pressure of the pipeline, permitted a zone of near-neutral stress corrosion cracking to initiate and grow to failure'. The TSB also noted that 'extensive research has found that the development of SCC requires shielding of the CP system by the exterior coating (coating disbondment), the absence of an effective CP system, or a CP system where there are variable CP levels over time. Although the line was protected with an asphalt exterior coating, the exterior coating can degrade over time to the point that water and moisture can migrate through the coating, enabling the CP potential through the asphalt coating. ... Insufficient CP levels may have occurred from time to time as a result of factors related to the pipeline, with decreasing CP system efficiencies or with varying resistivities of local soil conditions. ... the occurrence area was found to be in a transitional environment zone'. The TSB found that as the operator did not assess the risk as justifying the cost of the use of an In-Line Inspection crack detection device (but it had used a magnetic flux leakage in-line inspection tool which is not designed to identify zones of cracking), and that this may require revision, particularly as ILI devices had been commercially available since 1999.

CSB investigations

On 23 March 2005 an explosion and fire in BP's Texas City refinery killed 15, injured 180 and led to US$1.5 billion losses. The US Chemical Safety and Hazard Investigation Board (CSB) investigated and, in addition to safety recommendations during the investigation, released a 341 page final report on 20 March 2007. Further valuable perspectives are provided in the 16 January 2007 Baker Panel Report commissioned by BP and in the 2008 book *Failure to Learn* by Professor Andrew Hopkins. While the 'proximate cause' of the accident involved the start-up of an isomerisation (ISOM) unit and massively over-filling a 'raffinate splitter' hydrocarbon distillation tower, causal factors went well beyond human error, procedural breaches, and inadequate equipment and systems. After the 23 March 2005 explosion and fire there were two further serious incidents at the refinery in 2005 and, most recently, on 14 January 2008 the top of a large steel filter housing blew off in the refinery's cracker unit leading to the third fatality since 23 March 2005.

The CSB report into the March 2005 accident, like major ATSB reports and the NASA space shuttle investigation reports, examined both technical and organisational causes and highlighted key issues involving safety culture, regulatory oversight, process safety and human factors. Serious issues with safety culture, cost-cutting and deficiencies at all levels were traced back to BP in London. On the regulatory side, the CSB was critical of the effectiveness of the US Occupational Safety and Health Administration (OSHA) which conducted several pre-explosion inspections, primarily in response to fatalities, but failed to identify the likelihood of a catastrophic incident. It had an OHS focus on personnel safety and gave little attention to major process accident safety and risk despite many prior incidents and warning signs. The initial process hazard analysis (under May 1992 Federal Code 29 CFR 1910.119) and subsequent revalidations for the ISOM unit failed to identify the possible scenario of tower overfill leading to a liquid release. Therefore, 'instruments, such as the level transmitter were not identified as critically important to prevent column overfill and the potential for a catastrophic liquid release from the vent, and as a consequence were not placed on a priority schedule for maintenance and inspection'. There were also issues with process data, management of change, and mechanical integrity not picked up by OSHA. The NTSB had found in 2002 that OSHA was seriously deficient.

After the explosion 'Despite the large number of violations on the ISOM unit, and these two additional serious incidents in 2005, OSHA did not conduct a comprehensive inspection of any of the other 29 process units at the Texas City refinery'. The CSB found again that:

> *OSHA's capability to inspect highly hazardous facilities and to enforce process safety regulations is insufficient; very few comprehensive process safety inspections were conducted prior to the ISOM incident and only a limited number of OSHA inspectors have the specialized training and experience needed to perform these complex examinations.*

Such reports as the foregoing are publicly available and could have been studied by Apache to prompt consideration of any of its own safety and integrity vulnerabilities.

Annex 12: Reports by the WA Auditor-General

The Auditor General for Western Australia's October 2008 report *Improving Resource Project Approvals* found, among other things, that up to March 2008 approvals by DOIR had worsened. Analysis of quarterly reports from December 2005 to March 2008 showed that DOIR completed 291 approvals of petroleum environmental plans with 93 per cent within the set time of 42 days but the percentage declined to 79 per cent in the first quarter of 2008. It is stated that despite increased funding from 2003, the combined impact of the resources boom and loss of staff had contributed to backlogs and delays. Despite attraction and retention strategies, in 2006–07 DOIR's petroleum branch had eight advertised vacancies out of 40 positions. The Auditor General recommended that:

> *To ease staffing pressures, agencies should reconsider employing accredited consultants, using proponent-funded certified assessors, and establishing expert panels, as previously endorsed by Government.*

We are concerned that such a strategy could lead to conflicts of interest and a diminution of frank written advice on safety-related matters because of the influence of operators in paying consultants and experts.

In addition, the audit found that DOIR's guiding framework for State Agreements did not exist in any consolidated form and it was recommended that DOIR should make transparent the Government policy and factors it takes into account when facilitating approvals of new projects or project expansions on behalf of the State.

The Auditor General for Western Australia's November 2005 *Third Public Sector Report 2005* included a follow up to the June 2002 report *Level Pegging: Managing Mineral Titles in Western Australia*. The 2002 report listed a number of concerns leading to recommendations and shortly after the then Department of Mineral and Petroleum Resources (DMPR) was incorporated into DOIR. The 2002 report included that DMPR should 'review recordkeeping practices to ensure completeness and accuracy of records (in particular the tenement files) and compliance with the new *State*

Records Act 2000 and Departmental recordkeeping policy'. The 2005 report found that DOIR had addressed this problem.

However, we have found with respect to the records related to our terms of reference that the standard of recordkeeping within the DOIR Petroleum Division is poor and the new Department of Mines and Petroleum has agreed with this in its submission to this Inquiry.

The Auditor General for Western Australia's June 2004 report *Developing the State: the Management of State Agreement Acts* notes that at the time there were 64 such agreements administered by the Department of Industry and Resources. These include the *Oil Refinery (Kwinana) Agreement Act 1952*, the *North West Gas Development (Woodside) Agreement Act 1979*, the *Goldfields Gas Pipeline Agreement Act 1994*, and the *Barrow Island Act 2003*. The report found that it was unclear why some resource projects are established and operated under Agreements and others under existing statutory laws and also that reporting was often weak and lacking in transparency.

We consider that use of existing laws (for example to define the Varanus Island hub as a pipeline) and associated compliance and reporting arrangements also had significant deficiencies.

Annex 13: Guidance from ICAO on SMS, and the architecture of Australian aviation

ICAO

The International Civil Aviation Organization (ICAO) is the United Nations body responsible for the safety of aviation and has more than 190 states as members. It regulates through annexes to the Convention on International Civil Aviation (Chicago Convention) which contain standards and recommended practices (SARPS). Aviation is on the leading edge of many areas of safety. ICAO published the first edition of its *Safety Management Manual* in 2006 and a draft second edition is also available for free download on the ICAO website. The following key extracts are from the 2006 manual, Document 9859 AN/460.

Like other safety bodies, ICAO notes that: 'Safety is the state in which the risk of harm to persons or of property damage is reduced to, and maintained at or below, an acceptable level through a continuing process of hazard identification and risk management.' ICAO differentiates between safety programmes and safety management systems (SMS): 'A safety programme is an integrated set of regulations and activities aimed at improving safety' while 'A safety management system is an organized approach to managing safety, including the necessary organizational structures, accountabilities, policies and procedures.'

> *ICAO 'require establishment of a safety programme to achieve an acceptable level of safety in aviation operations ... by the State(s) concerned ... [and] may include provisions for such diverse activities as incident reporting, safety investigations, safety audits and safety promotion. To implement such safety activities in an integrated manner requires a coherent SMS*

> *[Therefore] … States shall require that individual operators, maintenance organizations, ATS providers and certified aerodrome operators implement SMS accepted by the State. As a minimum, such SMS shall: identify safety hazards; ensure that remedial actions necessary to mitigate the risks/hazards are implemented; and provide for continuous and regular assessment of the safety level achieved. An organization's SMS accepted by the State shall also clearly define lines of safety accountability, including … senior management.*

ICAO stresses that 'acceptable level of safety' is the overarching concept and regulatory compliance has to be complemented by a performance-based approach. Further, an 'acceptable level of safety' can vary across industry sectors and should be set with regard to implied risk, cost-benefit of improvements, operational context and complexity, and public safety expectations. ICAO says an 'acceptable level of safety' is expressed through safety performance targets and safety performance indicators, and implemented through safety requirements.

ICAO states that many bodies share responsibility for safety and effective safety management and sees 'considerable merit' in a regulatory system with 'a well-balanced allocation of responsibility' between the regulator and the operator or service provider that is justifiable given the economic resources of the State and a risk-based regulatory resource allocation[161].

ICAO believes that specialist independent accident and incident investigation authorities are important to avoid potential conflicts of interest.

A positive safety culture is crucial, including: senior management safety emphasis; a realistic view of short and long term hazards; fostering feedback and dealing with safety deficiencies; a non-punitive 'just culture' (but punishment if culpability); communicating safety at all levels; good training and learning; a safety ethic so little risk-taking behaviour; human factors understood and defences in place; and pro-active data gathering, analysis and response.

161 The oil and gas industry safety management structure is based on very similar principles established in the safety case regime operative in many parts of the world, including Australia. How responsibility is shared and what balance is best set between prescriptive and performance-based elements is the perennial challenge of a co-regulatory system.

Australian aviation safety architecture

Reflecting the very strong international and safety focus of the aviation industry and best practice governance suggested in Annexes to the Chicago Convention and ICAO guidance material, there are increasingly well defined public sector separations involving safety within Australian aviation. Typically policy, allocation and industry promotion is separated from operational safety regulation and compliance activity, but best practice also separates safety investigation from other roles. In best practice regimes, after an accident or serious incident, the regulator's investigative role has a limited regulatory compliance focus while a separate body undertakes a systemic 'no-blame' investigation of all causal factors involved (which may involve safety culture and/or errors and omissions by the regulator) with the sole aim of enhancing future safety.

In Australia, industry policy, coordination and legislative change is managed for the Commonwealth portfolio Minister by the Department of Infrastructure, Transport, Regional Development and Local Government. The Department also provides the staff for the International Air Services Commission which allocates airspace rights. The Department undertakes a number of other activities such as international negotiations, and the regulation of airport noise and security.

The Civil Aviation Safety Authority (CASA) is an independent statutory authority established in 1995 under the *Civil Aviation Act 1988* to regulate aviation safety in Australia and the safety of Australian aircraft overseas. While the safety regulation of civil aviation remains its primary role, CASA also provides safety education and training programs and in recent years has acquired responsibilities for airspace regulation and some environmental issues. In fulfilling its responsibilities CASA sets aviation standards, certifies aircraft, maintenance organisations and operators, licenses pilots and engineers, carries out safety surveillance, enforces safety standards and promotes industry awareness and understanding of aviation safety standards and safety issues. CASA's 600 staff oversee the activities of over 42,000 licensed industry personnel (including pilots, Licensed Aircraft Maintenance Engineers and Air Traffic Controllers), over 13,000 registered aircraft, more than 850 general aviation operators, more than 40 airline operators, over 700 maintenance organisations, more than 170 certified aerodromes, more than 130 registered aerodromes, and 26 air traffic control (ATC) facilities including major ATC centres in Brisbane and Melbourne.

CASA seeks to work constructively with the industry it regulates while taking firm regulatory action against industry where necessary to ensure safety. After several changes of direction, CASA has decided to adopt the European Aviation Safety Authority (EASA) model of regulation with high level legislation plus guidance material which, if followed, provides an acceptable means for compliance. Industry can propose alternative means for compliance that are better suited to their particular operations and are at least as effective.

Airservices Australia is a government-owned body that operates commercially under a board and CEO and provides air traffic control and aerodrome fire fighting and rescue services and is regulated by CASA in much the same way as CASA regulates major operators such as Qantas, Virgin Blue and Sydney Airport.

The Australian Transport Safety Bureau (ATSB) is a multi-modal no-blame safety investigation body that investigates accidents and incidents across the aviation industry and involving international and interstate ships and interstate rail. The ATSB performs its functions in accordance with the *Transport Safety Investigation Act 2003* (the TSI Act). It has a similar role to investigate under the *Space Activities Act*. Section 7 of the TSI Act defines the object of the Act as to improve transport safety through, among other things, independent investigations of transport accidents and incidents and the making of safety action statements and recommendations that draw on the results of those investigations. It is not the purpose of ATSB investigations to lay blame or provide a means for determining liability. The ATSB's main office and laboratories are in Canberra and it has field offices in Adelaide, Brisbane and Perth. As well as investigating individual aviation accidents and incidents, the ATSB also looks at systems and trends where these might provide information on future safety issues.

While the ATSB's investigation powers are vested in its Executive Director under the TSI Act to provide for operational independence, currently the ATSB is located within the Department and its staffing and budget are through the Department. The Government has legislated to make the ATSB a statutory authority with its own budget and staffing to enhance its independence. From 1 July 2009, it is to be led by a Chief Commissioner who will be the full time CEO, and at least two part-time Commissioners.

If the Australian aviation architecture was applied to the oil and gas industry, it would lead to ensuring that safety regulation was separate from departments that have a policy, allocation and industry promotion and development role. It would also mean that a no-blame systemic investigator would be established that could independently investigate accidents and serious incidents to a level that established root causes and other factors including any role of the regulator that either led to the accident or failed to prevent it.

Annex 14: Possible impacts of the national review into model OHS laws

Purpose of this annex

In this annex, we consider:

a) key findings and recommendations of the recent national review into model OHS laws ('the national OHS review'); and

b) how decisions about the recommendations in the review's reports may affect safety regulation in relation to the petroleum, gas and maritime industries.

We also suggest possible action by the responsible Ministers.

Background

In 2008, the Workplace Relations Ministers Council (WRMC) established the national OHS review. It was conducted by a three member expert panel. The purpose of the review was to make recommendations for the optimal content of a model OHS Act, which could be implemented as nationally consistent laws by the Commonwealth, States and the Territories. Under an intergovernmental agreement signed by the Prime Minister, the Premiers and the Chief Ministers,[162] this objective is to be given effect by the end of 2011.

As required by the review's terms of reference, the panel has presented two reports to the WRMC.[163] The reports are lengthy and contain 232 recommendations.

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162 COAG, *Inter-Governmental Agreement for Regulatory and Operational Reform in Occupational Health and Safety*, 3 July 2008

163 The reports, which were presented on 30 October 2008 and 30 January 2009, are available at <www.nationalohsreview.gov.au>

Relevant findings and recommendations in the reports of the national OHS review

With the assistance of one of the expert panel members of the national OHS review, we have considered key findings and recommendations that appear relevant to our inquiry. We have given particular attention to those relating to:

a) the scope of the proposed model OHS law;[164]

b) the duties of care and the consequences of non-compliance;[165]

c) other OHS obligations;[166]

d) workplace participation, representation and consultation;[167]

e) OHS issue resolution;[168]

f) the role, powers and functions of the regulator;[169]

g) permits and licensing[170].

Scope

In relation to the scope of the model OHS law, the national OHS review drew attention to the plethora of laws in Australia regulating OHS in a wide range of contexts. Considerable overlap was found between the primary OHS laws and other laws regulating health and safety in specific industries or in relation to specific hazards. The review found that, although a single OHS legislative system would conform to the Robens model, separate legislation may be justified for some types of industries or hazards.

Therefore, the review recommended a wider scope of the principal OHS Act in each jurisdiction, with separate regulation of OHS in specific industries or in relation to specific hazards only where it is periodically and objectively justified. As far as possible, the separate legislation should be consistent with the nationally harmonised OHS laws.

164 National Review into Model OHS Laws: Second Report to WRMC – January 2009, chapter 20

165 National Review into Model OHS Laws: First Report to WRMC – October 2008, Parts 2 and 3

166 National Review into Model OHS Laws: Second Report to WRMC – January 2009, Part 8

167 Ibid, Part 7

168 Ibid, Part 7

169 Ibid, Part 9

170 Ibid, Part 8, chapter 34

Where the continuation of separate legislation was not so justified, the review proposed that it be replaced by the model Act within an agreed timeframe. The panel recognised that the WRMC may not be responsible for some of the other OHS-related laws and therefore recommended that the WRMC ask COAG to consider taking the recommended approach forward in those areas. This would involve COAG asking the relevant Ministerial councils to examine the relevant laws in their areas of responsibility and to consider whether separate regulation was warranted. If so, the Ministers would also be asked to consider whether the relevant safety laws should be made consistent with the model OHS Act.

The review noted that there are various other initiatives proceeding under the aegis of COAG that related to some of these areas of regulations (including the establishment of a single national system of maritime safety regulation [171]). This would facilitate the consideration of whether OHS regulation should be rationalised.

Duties of care

After examining the existing diverse provisions relating to the duties of care and noting the varying jurisprudence in the jurisdictions, the review recommended a clearer, common approach.

A primary duty of care

There would be a primary duty of care, subject to reasonable practicability, placed on persons conducting a business or undertaking (rather than on employers or deemed employers). This would provide a more effective and dynamic way of dealing with the many new and emerging work relationships that are replacing traditional employment relationships.

The primary duty of care would require the duty holder to ensure so far as is reasonably practicable that workers engaged in work as part of the business or undertaking and any other persons are not exposed to a risk to their health or safety from the conduct of the business or undertaking.

The duty would expressly apply where the primary duty holder provides accommodation to a worker, where it was necessary to enable the worker to undertake work.

Various specified persons would also have that primary duty expressly placed on them. As well as the usual classes of designers, manufacturers, suppliers, erectors, installers, etc, a specific duty of

171 Australian Transport Council, Joint Communiqué, 7 November 2008, p.2

care would be placed on a person with management or control of a 'workplace' (widely defined).

In addition, the primary duty would apply to OHS service providers. These would be defined as including persons engaged by another duty holder to provide advice on OHS, systems, policies, procedures, etc, relating to the management of OHS, OHS training, and OHS testing, analysis, etc. Persons who exercise a power or perform a function under an Act would be excluded, as would members of emergency service organisations and legal practitioners when providing advice to which legal professional privilege applies.

A proactive duty of care for officers

Officers (as defined in the Corporations Act) would have a proactive duty of care. This is in contrast with the current position under which officers are typically taken to be liable where there is a breach by a corporation, subject to certain defences being available to the officers concerned. This duty would be subject to due diligence.

The duty of care for workers and others

Workers and others at a workplace would also have a duty of care, subject to reasonable care. The term 'worker' would defined widely to accommodate the continuous process of change in working relationships.

Offences

In the event of a breach of a duty of care, there would be three types of offences. The focus of the offences would primarily be on the level of culpability, not the outcome of the breach.

a) Category 1 offences would apply where the breach involved gross negligence or recklessness and serious harm to a person or the risk of such harm.

b) Category 2 offences would deal with cases where there was serious harm or the risk of it without recklessness or negligence.

c) Category 3 offences would apply to other breaches.

Category 1 offences would be indictable offences (proceedings would normally be before a judge and jury).

There would be no right of private prosecution for breaches.

Sanctions

The review recommended substantial increases in fines (up to a maximum of three million dollars for a corporation convicted of a category 1 offence), imprisonment (up to five years for an individual convicted of a category 1 offence) and a very wide range of sentencing options for courts, including fines, injunctions, remedial orders, training orders, and corporate probation. The maximum fines specified in the model legislation for corporations would be five times the maximum fines for individuals.

Regulators would also be empowered, subject to certain safeguards, to accept enforceable undertakings as an alternative to prosecution, other than for category 1 offences.

Other OHS obligations

The national OHS review recommended a range of particular obligations be provided for, including:

a) monitoring the health and safety of workers and conditions at a workplace;

b) requiring a person conducting a business or undertaking to employ or engage a suitably qualified person to advise on health and safety matters (in the case of larger businesses or undertakings, there would be a specific obligation to appoint a workplace health and safety officer);

c) incident notification to a regulator would be required, but would be limited to the most serious incidents; and

d) workers would be required to report any illness, injury, accident, risk or hazard of which they are aware arising from the conduct of the work to the person conducting the business or undertaking or the person with management or control of the workplace.

Workplace participation, representation and consultation

Numerous recommendations were made in this area. Broadly, the national OHS review recommended that an obligation be placed on persons conducting businesses or undertakings to consult workers and for duty holders to consult one another where their duties overlapped. There were also recommendations for the election of Health and Safety Representatives (HSRs) representing work groups, for the powers and functions of HSRs (including the issuing of Provisional Improvement Notices) and for their being granted paid leave to undertake competency-based training in relation to their roles as HSRs. There were also recommendations relating to the establishment and functions of Health and Safety Committees.

In related recommendations, the review proposed that the model legislation provide for the authorisation of union officials to exercise rights of entry at workplaces for purposes of consultation (with twenty-four hours notice) or investigating suspected breaches (without prior notice, but subject to a requirement to notify an appropriate person as soon as practicable after entry). Various safeguards were recommended. The recommendations were framed to align the right of entry provisions under the model Act with those under federal industrial relations laws, including those proposed in the Fair Work Bill 2008.

Strong protection against victimisation, discrimination and coercion was proposed, with a combination of civil and criminal remedies.

OHS issue resolution

A process of resolution of disputes or concerns relating to OHS matters was recommended, with a focus on informal consultation at the workplace, escalating to an inspector or a court or tribunal with powers of conciliation or arbitration. The court or tribunal would not be able to deal with a matter that was the subject of a provisional improvement notice.

Role, powers and accountability of the regulator and inspectors

As to the role, powers and functions of the regulator, the review emphasised the importance of graduated enforcement, the importance of information, education and advice from the regulator, the ability of the regulator to secure compliance by various means (consistently with the well-known enforcement pyramid) and the need for well trained inspectors to have the skills and understanding to secure compliance.

In this respect, the national OHS review noted the resource constraints facing most regulators and proposed that provision be made for the cross-appointment of inspectors in the various jurisdictions. In addition, the review recommended that the various Acts make it clear that evidence that was gathered in one jurisdiction could be validly used in another. Again, the review referred to the importance of the accountability of regulators and inspectors.

Permits and licensing

The review was required to consider permits and licensing arrangements for those engaged in high risk work and the use of certain plant and hazardous substances. The review recommended that engaging in such high risk activities without the relevant authorisation should be an offence. The detail of the authorisation process would be stipulated in regulations. Mechanisms would be established for mutual recognition of such authorisations.

OHS regulation in the petroleum, gas and maritime industries

As we discuss elsewhere, the regulation of these industries involves a complex mosaic of Commonwealth and State (or Territory) legislation. These laws include:

a) the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cth);

b) the *Occupational Health and Safety (Maritime Industry) Act 1993* (Cth);

c) the *Navigation Act 1912* (Cth);

d) the *Occupational Safety and Health Act 1984* (WA), except for workplaces that are, or work carried out on, petroleum wells or petroleum pipelines to which the *Petroleum and Geothermal Energy Resources Act 1967* (WA), the *Petroleum Submerged Lands Act 1982* (WA) or the *Petroleum Pipelines Act 1969* (WA) apply;

e) the *Petroleum and Geothermal Energy Resources Act 1967* (WA);

f) the *Petroleum Submerged Lands Act 1982* (WA);

g) the *Petroleum Pipelines Act 1969* (WA);

h) the *Western Australian Marine Act 1982* (WA);

i) the *Dangerous Goods Safety Act 2004* (WA).

Under s.89 of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cth), State and Northern Territory OHS laws do not apply to:

a) a facility located in the offshore area of a State, the NT or the Territory of the Ashmore and Cartier Islands;

b) activities at such a facility; or

c) a person at such a facility, a person near such a facility affected by the facility or activities at the facility.

A facility is, for these purposes, defined in cl.4 of Schedule 3, Occupational Health and Safety, of the Commonwealth Act and, in specified circumstances, may be constituted by a vessel, structure or a pipeline. Otherwise, State or NT OHS laws will apply within their jurisdictional competence.

Implications for these laws of the national review

Of the Commonwealth and State laws mentioned above, those most likely to be directly and immediately affected by the national review's findings and recommendations are:

a) the *Occupational Health and Safety (Maritime Industry) Act 1993* (Cth);

b) the *Occupational Safety and Health Act 1984* (WA).

Each is administered by a Minister, who, in accordance with the Inter-Governmental Agreement, is responsible for implementing agreed matters arising from the national review.

If the national OHS review's recommendations were acted upon, there would be substantial changes in a number of areas (particularly in relation to duties of care and the consequences of non-compliance).

In the longer term, Ministers in other portfolios may be requested by COAG to examine laws that they administer which affect OHS to justify the continued separate operation of those laws. This may affect the petroleum and gas regulation that is the subject of our inquiry.

Even if no action were to be taken following the national OHS review, we consider that close attention should still be given to certain underlying concerns identified by the national OHS review. These relate to the inefficiency and potential confusion caused by too many sources of regulation. Even apart from the question of how well the laws identified above have been administered, there is considerable potential for difficulties to arise from their interaction, given the differing provisions and regulatory practices associated with them. Rationalising the laws, improving their interaction and having more effective coordination of their administration should be a priority.

Suggested action

The existing principal OHS Acts in the various jurisdictions appear likely to be amended in line with the proposed model OHS Act to achieve national consistency. Those amendments will be based on the decisions of the WRMC about the content of the laws, after the WRMC has considered the two reports of the national review. It is probable that various other laws that relate to OHS will at least be made consistent with the national model OHS law. We are not, however, in a position to speculate on whether the principal OHS laws will absorb any of the OHS regulation that is provided in relation to the maritime industry or the offshore and onshore oil, gas and petroleum industries.

We suggest two alternative courses of action.

Suggested approach if recommendations about justifying separate OHS laws are accepted

If COAG agrees that separate, industry or hazard specific laws relating to OHS should only be maintained where objectively justified, careful consideration will be required to see whether such justification exists. If the separate legislation is justified, then, in line with the review's recommendation, further careful examination would be required to justify any variation from the nationally consistent principal OHS laws.

To prepare for such a process, we recommend that there be full and early engagement with all interested parties, including industry bodies, operators, unions and regulators for the purposes of that examination to identify and evaluate the options.

Suggested approach if recommendations about justifying separate OHS laws are not accepted

If those recommendations are not accepted by WRMC or COAG, we propose that the Commonwealth and WA should nonetheless reconsider the content and operation of all laws in the petroleum and gas industry that affect OHS.

The aim should be to achieve as much consistency with the content and operation of the harmonised principal OHS laws as is appropriate. We consider that the benefits of doing so would be considerable, for reasons including:

a) reducing the regulatory burden on duty holders who are subject to more than one OHS regime;

b) using OHS regulatory resources more efficiently; and

c) facilitating the entry of workers to the industry by ensuring that there are, as far as possible, OHS rights and responsibilities that are consistent with those under general OHS laws, thereby reducing the amount of training required.

Annex 15: The effectiveness of OHS regulation by NOPSA and DOCEP

Purpose of this annex

We discuss the effectiveness of regulation of OHS by NOPSA and DOCEP. We note the impact of changes in administrative arrangements in WA relating to onshore oil and gas safety. The resource safety responsibility transferred to DOCEP on 1 July 2005 was transferred to the new Department of Mines and Petroleum on 1 January 2009.

Background

We have outlined the history of NOPSA elsewhere. We have noted that NOPSA regulates the health and safety provisions of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* in Commonwealth waters and the Western Australian *Petroleum (Submerged Lands) Act of 1982* in designated coastal waters. This covers offshore platforms and pipelines that feed into the Varanus Island hub. The hub itself is primarily regulated by licence under the Western Australian *Petroleum Pipelines Act 1969* by DOIR.

Similarly, we have referred to DOIR having responsibility for OHS and integrity for the onshore (mainland) portions of the gas export pipelines. From July 2005 to the end of 2008, DOCEP provided, under an MOU, regulatory services to DOIR for these portions of the pipelines. The regulatory role is now undertaken by the Department of Mines and Petroleum (DMP), which also administers the *Dangerous Goods Safety Act 2004* and *Dangerous Goods (Major Hazard Facilities) Regulations 2007*.

How to assess the effectiveness of OHS regulators

OHS regulatory performance is notoriously difficult to measure. There is a lack of objective data that allow complete and definitive conclusions to be reached about the performance and influence of a regulator. This is partly because there are many factors that affect OHS outcomes, apart from the regulator's activities.

Some commonly used methods include:

a) measuring trends in overall OHS performance[172];

b) ad hoc assessments of the impact of particular programs or interventions[173];

c) surveys of those who are subject to the legislative regime administered by the regulator[174];

d) intermediate performance indicators (e.g., the extent to which duty holders have adopted particular measures promoted by the regulator to address hazards and risks; the extent to which recognised best practice regulatory methods are used; the numbers of proactive workplace visits by inspectors compared with reactive interventions[175]);

e) consideration of the views of stakeholders on the regulator's policies and practices in relation to securing compliance[176].

Performance must be assessed against a range of criteria. There appears to be no single reliable, objective method of assessing performance. Various factors may lead to a false impression about performance. For example, in an industry where major incidents are low frequency but have highly serious consequences, apparently

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172 The Comparative Performance Monitoring program compares Australian and NZ OHS and workers compensation schemes at a broad level (see the 10th Comparative Performance Monitoring report, Commonwealth of Australia, August 2008). DOCEP's 2007–08 Annual Report refers to the overall reduction in injury and disease rates as a measure of agency performance.

173 For example, the Heads of Workplace Safety Authorities coordinate and evaluate programs of interventions in areas of particular hazard and risk, e.g., in relation to the prevention of falls, safer manual handling. See <www.hwsa.org.au/activities/activities-campaign_final_reports.aspx>

174 These may be conducted on an ad hoc basis or to meet a statutory requirement (e.g., the 2007 NOPSA stakeholder survey).

175 10th Comparative Performance Monitoring report, op cit.

176 Stakeholder views on OHS performance tend to be obtained through representative bodies (e.g., the WA Occupational Health and safety Commission). They are usually sought on a wider basis in the course of inquiries and reviews, but do not provide much information that allows trends to be identified. Surveys are less frequently undertaken on a systematic basis (e.g., the DOCEP surveys about the effectiveness of its ThinkSafe campaigns).

good OHS results may simply mask incompetence or indifference. The true picture may not be clear until after a serious event has occurred.

The involvement of other regulators

We consider elsewhere in our report the problems of overlapping regulation in the context of the events that are the subject of our inquiry. Such problems are compounded where there are inadequate arrangements between the responsible regulators for coordinating their efforts and achieving their common and complementary goals. In relation to safety in the oil and gas industries, the challenge is magnified not only by the operation and interaction of Commonwealth and State jurisdictions, but also the legislative and administrative arrangements that have operated in WA.

The WA Department of Mines and Petroleum (DMP) drew our attention to the impact of the commencement of NOPSA's operations in 2005. According to DMP, at that time half of the technical staff in the relevant resources safety area of DOIR took up positions with NOPSA and most of the rest were transferred to DOCEP. DOIR then had approximately one FTE position to discharge its ongoing regulatory responsibilities and, as we discuss elsewhere, relied on arrangements with DOCEP and NOPSA to carry out operational tasks. It is self-evident that this was not a satisfactory situation, but, as we note, it continued for some time.

Interaction of law and practice

The regulatory task is crucially dependent on the legislation that gives regulators their roles, powers and functions. If there are shortcomings in the legislation, it will be difficult for even the most skilled regulator to overcome them by administrative means. In this regard, we note that NOPSA was given regulatory responsibilities under relatively modern OHS legislation [Schedule 3 of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwth)]. On the other hand, as DMP has pointed out, the *Petroleum Legislation Amendment and Repeal Act 2005* (WA), which provides a comparable OHS regime, has for the most part not been proclaimed in the absence of the requisite accompanying regulations. This not only creates disparity in the regulation, but leaves the State regulator in the position of relying on a variety of Acts and regulations to address OHS issues, as well as having the field work performed by arrangement with other agencies (see above).

Information provided by the regulators

NOPSA outlines its OHS activities in its annual reports. For example, in the 2007–08 annual report, information is provided about the number, nature and type of OHS field operations and an analysis is provided of time spent on core regulatory functions as opposed to other activities. Some trends in OHS risks and problems discovered in those regulatory activities are described. On the other hand, information is not readily available about trends in NOPSA's regulatory performance from one year to the next, or comparisons with other regulators (whether in the industry or elsewhere).

The information provided publicly by DOCEP and DOIR appears less useful for assessing their OHS regulatory performance.

Summary

On the material before us, we have concluded that NOPSA should, through its processes of engagement with the industry and unions and other interested stakeholders, settle on a clear program of improvements to its performance as an OHS regulator. This would go beyond its current program for improvement and involve defined objectives and measures of performance that could show trends. This should not present difficulties, given NOPSA's positive approach to accountability and performance improvement.

For DMP, there appear to be many issues that require attention, including resources and the legislation under which it operates. Those are matters for government, but merit priority attention. In the meantime, DMP has the opportunity as a new Department to develop performance objectives and criteria. There may be value in NOPSA and DMP working together in this respect.

Annex 16: Learning from Major Accidents: Cullen, McInerney and Hopkins

There are a large number of major accident reports in offshore, refining and transport industries from which we can learn and that are indicative of the way a judicial inquiry might review a major multiple-fatality offshore accident in Australia. In the UK, Lord Cullen's reports into the Piper Alpha platform disaster and Ladbroke Grove rail accident are seminal. In Australia, the reports by Justice McInerney into the fatal Glenbrook and Waterfall rail accidents in NSW are important.[177] Professor Andrew Hopkins has analysed and summarised the lessons from the 25 September 1998 Esso Longford, Victoria gas explosion and Royal Commission, and from the 23 March 2005 Texas City refinery explosion reports.

Cullen Inquiries

Lord Cullen's two-volume report into the 6 July 1988 Piper Alpha explosions and fire that killed 167 of 229 on the offshore platform included 106 recommendations and formed the basis of the safety case regime, administered by the UK HSE, under which the offshore oil and gas industry must demonstrate that an effective safety management system is in place. Key was the unambiguous assigning to the company management of the responsibility for assessing risk and properly managing it. It also drove improvement in the quality of safety management, a rigorous permit-to-work system and good communication including across shifts, safety training including for emergencies and simulations, improved auditing, and

177 The US reports on the Challenger and Columbia space shuttle explosions and the Canadian report on the 1989 Dryden aviation accident by Justice Moshansky are similar landmarks.

the installation of automatically operating pipeline isolation valves as well as redesigning platform layouts to remove the most hazardous modules from proximity to accommodation.

About a decade later, Lord Cullen inquired into the 130 mph head-on passenger train collision on 5 October 1999 at Ladbroke Grove which killed 31 and injured 400 after one of the trains passed an obscured red signal. Lord Cullen found that 'There was a lamentable failure on the part of Railtrack to respond to recommendations of inquiries into two serious incidents' in November 1995 and February 1998. He was critical of the deficient regulator which suffered from 'a lack of resources, a lack of vigour in pursuing issues, and the placing of too much trust in duty holders'. In terms of their excuse of being 'overwhelmed with work' he said they should 'have pressed for more resources'.

McInerney Inquiries

The NSW Commissions of Inquiry into the multiple-fatality rail accidents at Glenbrook on 2 December 1999 and at Waterfall on 31 January 2003 reportedly cost about $20m and $40m respectively. Among other things, in Glenbrook, Justice McInerney was critical of operator safety culture and competency, the regulatory system, and the quality of accident/incident reporting and investigation managed by the regulator. His 95 recommendations included the need for a separate independent safety investigation body and learning from national and international best practice.
In the Waterfall Inquiry report, Justice McInerney was concerned that many of his previous recommendations had not been implemented and made a further 127 recommendations. These included improvements in emergency response, risk management, training, safety culture and governance, safety regulation, and the independent investigation of all future NSW major accidents and incidents by the ATSB.

Lessons from Hopkins

ANU Professor Andrew Hopkins has written a number of excellent books focussing on the organisational causes of disasters including the 2005 *Safety, Culture and Risk*. In his 2000 *Lessons from Longford: The Esso Gas Plant Explosion*, he analyses the 25 September 1998 accident that killed two men, injured eight others and cut Melbourne's gas supply for two weeks. He goes beyond the Royal Commission's findings that the operator was to blame and that the accident was preventable, to critically examine the submissions of the OHS regulator, Workcover, which argued ‘that the regulatory system was in no way a cause of the accident’. He notes that State Government support for the regulator appeared calculated to avoid criticism or blame. However, a safety case regime was proposed for the future. Hopkins’s other lessons for the oil and gas industry include: over-reliance on lost-time injury data in major hazard industries is itself a major hazard; systematic hazard identification is vital for accident prevention; corporate headquarters should maintain safety departments with enhanced oversight of the management of major hazards; frontline operators must be provided with appropriate supervision and backup from technical experts; routine reporting systems must highlight safety-critical information; maintenance cutbacks foreshadow trouble; and organisational mindfulness is required and companies should apply the lessons from other disasters.

Hopkins’s 2008 book, *Failure to Learn: the BP Texas City Refinery disaster*, provides a nuanced multi-factorial explanation of the causal factors underlying this 23 March 2005 disaster. Highlighting a poor safety culture led from the top and factors noted previously, Hopkins refers to the ‘normalised deviance’ found by the two US space shuttle explosion inquiries and BP’s blindness to major risk, in part created by an over-reliance on personal safety and OHS compliance, which could detract from process safety measures that could prevent catastrophic accidents. He found that corporate decentralisation and cost cutting exacerbated the problems and that a focus on financial indicators at the expense of safety was pervasive. For Hopkins, inquiries that focus on blame are largely incompatible with properly explaining an accident or serious incident.

In terms of regulation, the US regulator’s primary focus was also on personal safety and OSHA did not have the resources to enforce its process safety regulations effectively. In contrast, the UK regulator (the HSE) carried out detailed annual multi-disciplinary inspections of the nine refineries under its jurisdiction ranging from 80 to 150 days in duration. Hopkins states that ‘there is good scientific evidence that intensive regulatory scrutiny is an effective accident reduction strategy’ and notes that BP’s California refinery had a relatively better safety performance in part due to the intensity of State regulatory scrutiny. Hopkins argues that:

> *it is sometimes better to carry our risk assessments remote from the circumstances of particular decisions and to create rules that decision-makers must then comply with. In some cases these might be internal company rules, in some cases they might be contained in industry codes, and in some cases it might be appropriate to formulate them as regulatory requirements. In particular, where industry best practice is clear and relatively uncontroversial … [S]afety inspectorates could*

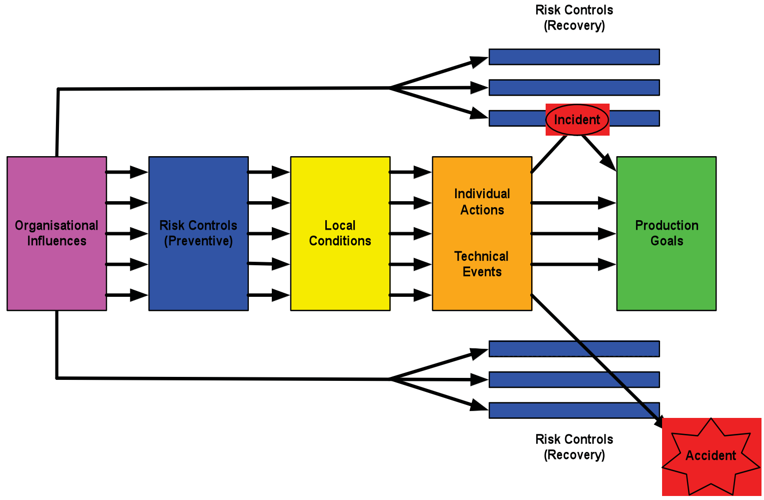
> *examine the position and powers of company safety specialists … pay incentive schemes … channels of communication … [and] insist that CEOs apply the same management of change requirements to their own decision-making, particularly with regard to company reorganisations and cost cuts, as is required at lower levels of a company … Depositions can hold people accountable – in the sense of requiring them to give an account of their actions and inactions … without fault'.*

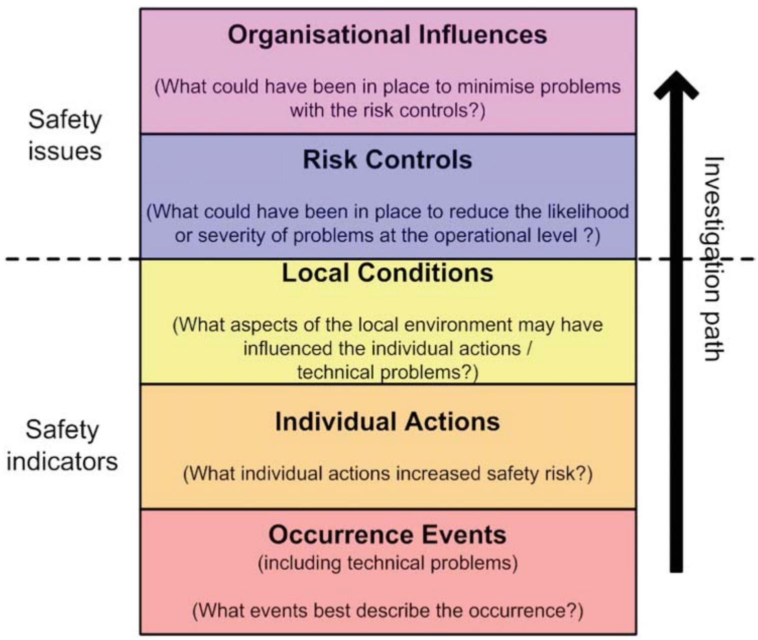
Operators such as Apache can learn much from major inquiries and monographs such as the foregoing. The Inspectors were impressed to be told that Santos's CEO had purchased 50 copies of Hopkins's *Failure to Learn* and circulated then widely around the company.

Annex 17: ATSB reports of relevance to Varanus Island and Offshore Safety Regulation

The Australian Transport Safety Bureau (ATSB) was established on 1 July 1999 and is the independent transport safety investigation body for aviation, marine and rail accidents under Commonwealth jurisdiction. Larger ATSB investigations are systemic, examining the whole safety system that led to a serious accident or incident. All reports are published direct to the public without fear or favour and are purely focussed on future safety rather than blame. The ATSB website <www.atsb.gov.au> has more than 1 million new users and 40 million 'hits' annually and includes about 1500 aviation, 250 marine and 50 rail final investigation reports, mandatory and confidential incident reporting, research reports and other safety material. Importantly, the ATSB is separate from any police or regulatory investigation that may seek to apportion blame or liability and, in the interests of safety, under the *Transport Safety Investigation Act 2003* the ATSB can compel evidence even if in other circumstances it could be incriminatory. The quid pro quo is that this cannot be then used in civil or criminal courts. Where relevant, major ATSB reports go beyond just documenting the relevance of immediate technical or human causal factors, and look at organisational, regulatory and other factors that may have contributed to the occurrence or to another contributing safety factor. The ATSB also reports on any other safety factors that may need to be addressed to reduce risk. A summary of the ATSB methodology is available on-line in the 2008 report *Analysis, Causality and Proof in Safety Investigations* by Dr Michael Walker and Mr Kym Bills and is built up from a Professor James Reason type model as illustrated below.

Figure 10: ATSB investigation analysis models

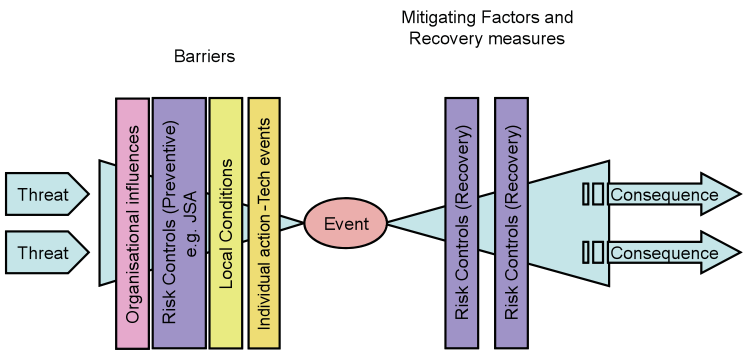




Bow-tie model

The oil and gas industry typically use a ‘bow-tie’ analysis for a safety case comprising four steps: identification of the top events with their hazards; assessment of all the potential threats and escalating factors, identification of control measures to prevent the hazard occurring or being released (the left side of the bow-tie) and identification of mitigation or recovery measures should the hazard occur (the right side of the bow-tie). The bow tie model can be mapped to the ATSB model as follows:

Figure 11: Bow-tie model compared with ATSB model



Major ATSB reports

A 1999 ATSB report into a trial of ‘class G’ airspace with less air traffic control type guidance in a busy corridor that led to a number of incidents was, among other things, critical of the regulator (the Civil Aviation Safety Authority) acting with both the Minister and CASA Chairman’s encouragement in advance of legislation being amended, and the inadequate safety analysis and a lack of industry education ahead of the trial. The investigation looked at higher level organisational factors including issues involving the CASA Board.

The ATSB final report into a runway over-run by a Qantas 747 on 23 September 1999 during heavy rain in Bangkok found that in addition to a number of errors and poor decisions in the cockpit, there were organisational issues with company training, procedures and culture including some linked to cost savings, and issues involving CASA in terms of regulations for wet runways, emergency procedures and training, and surveillance of Qantas operations.

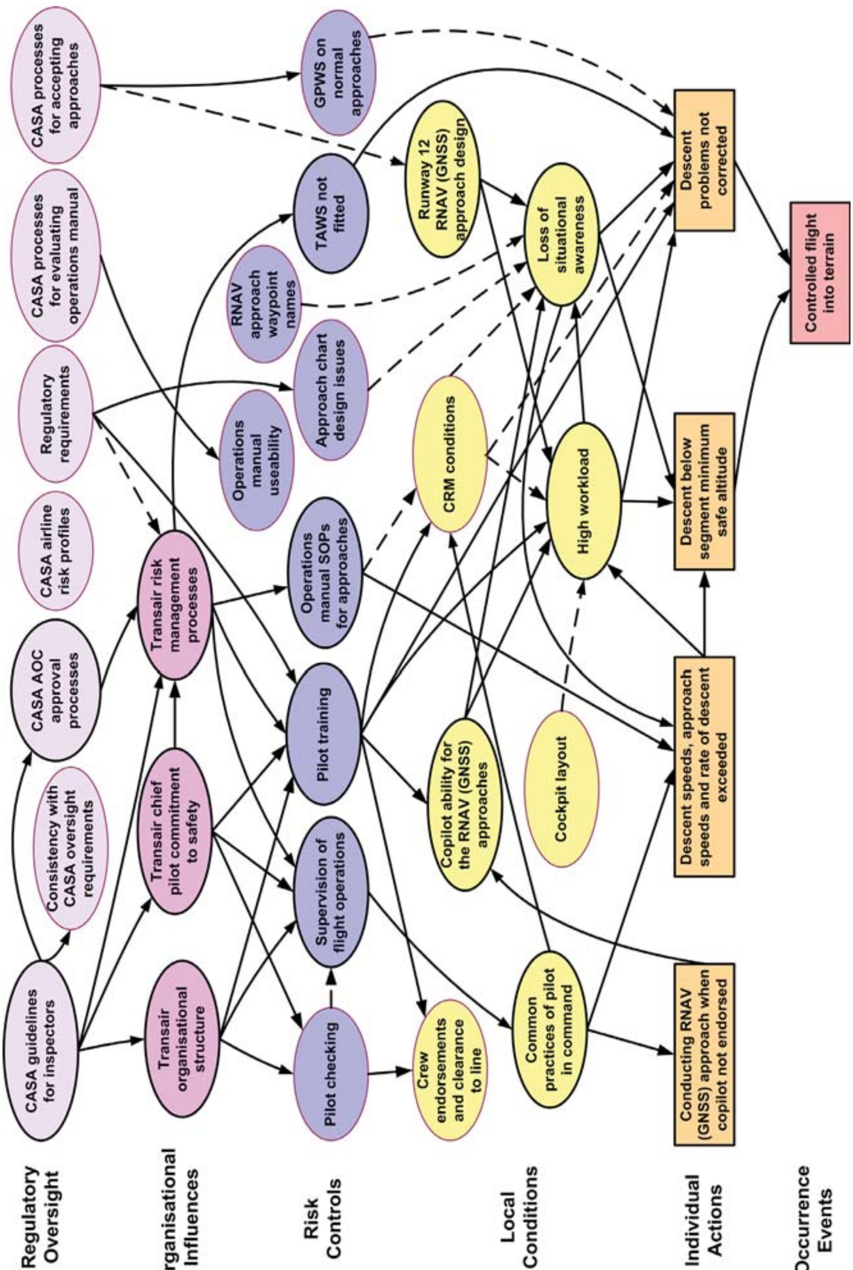
In March 2001 the ATSB released its final report into Avgas fuel contamination from Mobil’s Altona refinery that grounded thousands of aircraft in eastern Australia from January 2000. The ATSB found serious problems with the refiner's risk management and management of processes for the manufacture of Avgas which were relevant more broadly to managers of complex, safety critical systems, including the need for heightened mindfulness. There were issues with the development and use of international standards for Avgas, and also issues with a lack of regulatory oversight and a 'diffusion of responsibility' among regulators.

The ATSB final report in November 2002 into maintenance deficiencies that led to a lack of inspection of cracking in safety-significant areas of Ansett 767 aircraft found serious organisational issues within Ansett that allowed the problem to emerge. There were also issues with the Australian regulator, the US aircraft type regulator of Boeing aircraft – the US FAA, and with the UN international regulatory body, ICAO. There was inadequate sharing of safety information among regulators and hence an absence of closed-loop learning.

A final ATSB report into a 15-fatality scheduled passenger aviation accident was released in April 2007 following several reports and recommendations in the interim. The 'controlled flight into terrain' accident occurred in bad weather when the pilots lost situational awareness in the approach to Lockhart River aerodrome in Queensland. The ATSB had sufficient evidence to find 17 contributing safety factors with a probability of over 66 per cent (black outline ellipses in the diagram on the next page), 10 of which involved the pilots. However, there were five contributing safety factors involving the operator and two contributing safety factors involving CASA regulation.

In this case, the contributing safety factors included the poor commitment to safety shown by the company's Managing Director who was also overloaded as both Chief Pilot and check pilot and had another significant role in PNG with an associated company. The operator's safety management system comprised manuals which did not correspond to reality, internal safety incident reporting rarely led to follow-up action and training was often inadequate. While the regulator argued that the focus of the ATSB investigation should have remained with the pilots, the ATSB found that if CASA had done more to assess changes to the operator's Air Operator's Certificate as the airline expanded quickly and risk increased and changed, and had given better guidance to its inspectors, the accident may not have occurred.

Figure 12: ATSB investigation model applied to the Lockhart River accident



The methodology used in ATSB investigations results in the uncovering of underlying causes of serious transport accidents and incidents. The rigorous systemic process employed goes beyond the immediate contributing factors of such occurrences to examine deeper root causes and, in so doing, maximises the probability of preventing similar events. Better practice within the oil and gas industry has used similar techniques in the past with some success. A key advantage of the ATSB model is the independence of the investigating body from both the operator and regulator. This independence ensures the methodology is used without fear or favour and that the result will provide the best opportunity to minimise underlying risk and improve future safety. Another advantage is the ATSB's legislation and critical mass of professional investigations.

Annex 18: Productivity Commission Upstream Petroleum Regulation Review

The Investigation Team informed themselves of the work of the Productivity Commission (PC) by reading the December 2008 draft and the April 2009 Research Report on the Review of the Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector and meeting with Commissioner Mr Philip Weickhardt and secretariat member Mr Peter Garrick. We found a great deal of common ground between this inquiry and our investigation particularly in terms of the negative impacts from layers and complexity of multiple regulatory jurisdictions, bodies and interfaces which need to be further simplified, particularly in Western Australia. But there were also some areas where there was a divergence and where we believed there was a case to go further than suggested by the PC. The following highlights the main relevant areas of difference and emphasis.

We believe very strongly that any new national regulator such as the PC's proposed National Offshore Petroleum Regulator (NOPR) should not include NOPSA in either its current or an expanded form. We agree that NOPSA should be expanded to cover integrity of offshore pipelines and subsea equipment and the safety aspects of wells, as well as integrity more broadly where it goes beyond personal safety. But in our view, the case for maintaining separation of safety regulation from other forms of regulation and from policy and industry promotion and development is very strong and is not just a theoretical matter but one that has arisen repeatedly from experience with major accidents around the world. In addition to Lord Cullen's Inquiry into the 167 fatalities on Piper Alpha in 1988 where the dual Department of Environment (DOE) departmental role of industry resource management and safety regulation was identified as a problem, in the US the 1996 ValuJet DC9 accident involving 110 fatalities was quickly seen as involving a problem because the Federal Aviation Administration in the Department of Transportation had a 'dual mandate' whereby an industry promotion role could undercut safety regulation. More recently, Justice McInerney has recommended, in the context of major judicial inquiries into two multiple-fatality rail accidents in NSW, that safety regulation should be separate from other forms of regulation and of other government roles such as policy (see Annex 9). Justice McInerney also strongly supported the need for an independent and properly resourced no-blame systemic investigator to investigate serious accidents and incidents in the future. We strongly support this for the oil and gas industry but the PC report is silent on any need for such investigation.

The PC report considers an option in which the mandate of an expanded NOPSA includes regulation of onshore sections of integrated upstream facilities. However, it states that, on balance, it does not consider the option to be practical. While recognising the challenge involved, we believe that minimising unnecessary interfaces and taking a whole-of-process perspective is likely to reduce safety risk and improve regulatory effectiveness as well as efficiency. We agree with the PC that State/NT jurisdictions should have the option to delegate responsibility for the regulation of cross-jurisdictional onshore upstream pipelines to NOPSA. In addition, if some jurisdictions wished to have NOPSA regulate other upstream activities, including those located entirely onshore, this should also be facilitated through relevant legislative amendment.

The PC recommended, on balance, that NOPSA not have future responsibility for environmental compliance regulation and despite some good arguments either way on the issue, we support such a conclusion.

Annex 19: March 2008 Review of NOPSA and precursor reports since 1996

The February–March 2008 review of NOPSA and associated submissions provided helpful background to this investigation and we have many areas of agreement with its recommendations.

1996 report by Dr Tony Barrell

The context of the Barrell report on *The Regulation of Health and Safety in the Australian Offshore Petroleum Industry* was the 'objective-based' safety case regime that since 1992 had progressively replaced the traditional prescriptive regulatory system, with full effect expected from 1996. Barrel outlines the well-known four-fold disadvantages of prescriptive regulation in complex high hazard industries: that it is impossible to prescribe every process and activity; legislation becomes out of date; it inhibits innovation and cost effective solutions; and there is a transfer from employer to regulator of both risk and the responsibility for devising greater safety. He notes that prior to the 1988 Piper Alpha disaster, UK legislation was prescriptive and in some instances badly out of date, and there was criticism of the UK Department of Energy for allowing its twin functions of safety regulation and safety promotion and exploitation to become too intertwined. Lord Cullen's Inquiry into Piper Alpha emphasised the need for safety regulation to be handled separately outside the department responsible for resource management.

For Barrell, the four principles of a safety case regime are:

(i) that employers who create risks to their employees by practising their business activities are wholly responsible for controlling and reducing those risks;

(ii) that the regulator is responsible for administering the safety legislation and where necessary enforcing it;

(iii) that the legislation should be objective-based, in that it sets out the safety goals to be achieved, but does not prescribe the solutions;

(iv) that the approach to safety improvement should be risk-based, in other words all risks should be identified and the action taken to reduce them risks should then be proportionate to the size of those risks.'

In such a co-regulatory environment 'the regulator is expected to display independence, probity and competence. Moreover, it should work in an organised and systematic manner that is as transparent as possible to those who are regulated and to the public. It should operate at minimum cost consistent with achieving effectiveness, and it should endeavour to achieve high service standards in its dealing with its various clients and stakeholders.' These are principles still broadly applicable in 2009.

A number of serious concerns noted by Barrell also remain relevant. He felt 'particularly strongly that regulatory staff must keep on file proper written records of their visits offshore, and of their meetings with operators (particularly the actions agreed and the timetables associated therewith), and that they follow-up all meetings on the implementation of safety improvements promptly with letters confirming the substance of such agreements' because he found too much undocumented and 'insufficient evidence of actions by the Regulator'. Barrell stated that 'the penalties in the safety regulations available following successful prosecution are, in my view, quite inadequate for the possible gravity of the offences concerned' and 'there is confusion arising from the interface between the *Petroleum (Submerged Lands) Act* and the *Navigation Act* and that this ought to be clarified'. He also argued for companies to imaginatively improve communication about safety matters.

Barrell outlines common essential elements of safety case administrative systems, including: an annual operating plan specifically for safety with key objectives and performance measures; an annual internal review of performance against last year's plan, explaining reasons for any difference from plan; a definition of the responsibilities and accountabilities of safety personnel; a competency framework and a training plan to fill gaps; written internal procedures and standards covering the scrutiny of safety cases, inspection, service standards, communications with operators and others, auditing, etc; policy and guidance on inspection and enforcement and on ensuring probity; an accident/incident database and document control system; and internal arrangements for auditing systems and performance.

> *Barrell argues that in a safety case regime, the 'inspector has to be able to use the considerable analytical and*

> *reasoning powers necessary to uncover any weaknesses in the fundamental and comprehensive thinking that has gone into such safety cases, or in the design of the safety management systems. ... The qualities needed in an inspector are not primarily those to do with technical ability ... what counts is the intellectual ability to analyse and reason, the capacity to work in a systematic and thorough manner, the resolve to take an objective, detached and questioning approach and the determination to back one's judgement in the face of pressure ... to ask searching questions about the design and adequacy of the design and operation of management systems and have the judgement and experience to determine what is a satisfactory answer, when the matter needs to be pursued further and when enforcement action must be taken.*

He maintains that funding should enable inspectors to maintain professional networks and attend relevant conferences, seminars and the like.

The move from prescriptive legislation to the safety case regime has changed the role of the regulator as described above. Barrell stated that the resources required to carry out this role need to be tailored to the task if the regulation is to be effective in all respects. We believe that there is still more to do in this respect in 2009.

2000–2001 reports

Following an Independent Review Team (IRT) report of March 2000, and the earlier Longford Royal Commission criticism of the effectiveness of the implementation of safety management systems in onshore facilities, the Commonwealth coordinated consideration of recommendations and policy options with senior State/NT officials and published *Future Arrangements for the Regulation of Offshore Petroleum Safety* which reviewed the extant safety case regime administered by the States/NT. The report noted that data gathered in 1999 were inconclusive in terms of demonstrating whether or not the level of offshore safety had in fact improved since the introduction of the safety case regime. The primary IRT conclusion was that:

> *The Review Team is of the opinion that the Australian legal and administrative framework, and the day to day application of this framework, for the regulation of health, safety and environment in the offshore petroleum industry is complicated and insufficient to ensure appropriate, effective and cost efficient regulation of the offshore petroleum industry ... Much would require improvement for the regime to deliver world-class safety practice.*

The IRT found in March 2000 that:

- there were too many Acts, Directions and Regulations, their boundaries were unclear and there were overlaps and interpretation and application was inconsistent;
- guidelines are often applied as if they were compulsory regulations;
- provisions for graded sanctioning of non-compliance are absent;
- the use of consultants to assess safety cases can potentially cause a conflict of interest and consultants have closer ties to companies than with regulators; and
- lead performance indicators need to be developed.

Further, the IRT assessed that State/NT safety regulators lacked regulatory skills, capacity and consistency and did not have a clear view of their role, and that the level and competencies of Commonwealth staffing was also deficient.

However, the IRT noted that the States/NT continued to argue for the retention of a disaggregated regulatory system. Ultimately, the IRT recommended that a national petroleum regulatory authority similar to AMSA should be developed. With industry support, the 2001 report recommended the establishment of what became NOPSA.

The 2001 report outlines the key safety case rationale and elements that remain relevant:

> *Objective based (or goal setting) regimes, including the safety case regime, are based on the principle that the legislation sets the broad safety goals to be attained and the operator of the facility develops the most appropriate methods of achieving those goals. A basic tenet is the premise that the ongoing management of safety is the responsibility of the operator and not the regulator. Within this objective-based regime there is a requirement that the operator of an offshore petroleum facility must make a formal 'case' to the regulator which outlines the types of safety studies and analyses undertaken, the results obtained and the management arrangements in place to assure the continued safety of personnel on a particular facility. The 'Safety Case' must establish a strong enough argument, supported by evidence that will satisfy the regulator, that the operator knows what technical and human activity related safety problems exist, how they must be managed and how the safety of personnel will be assured in the event of an emergency. The safety case must also identify the methods used to monitor and review all activities to continually improve safety performance.*

The report states further that:

> *A typical offshore safety case comprises three elements – a Facility Description, a Safety Management System (SMS), and a Formal Safety Assessment (FSA) ... The results of the FSA and general safety studies are used to devise methods of eliminating or controlling hazards to reduce risks. It is a demonstration that risks to personnel have been reduced to as low as reasonably practicable (ALARP). … The SMS must be comprehensive, integrated and contain feedback loops that continually measure performance and drive change ... The primary focus of the safety case regime is on reducing the incidence of major accident events (MAEs). ... In general, a breach of an accepted safety case is a breach of the regulations. … it is generally now accepted that LTIs [a low level of lost time injuries] do not provide a good correlation with the likelihood of MAEs in the future.*

The 2001 report also cites a late-2000 discussion paper from the UK HSE outlining essential characteristics under which they operate their safety case regimes when giving consent or permission for an operator/duty holder to undertake an activity in the railway, nuclear, offshore and onshore major hazard industries. The HSE notes that through the democratic political process the regulator and the regulated are subject to society's views about the tolerability of risk and 'permissioning regimes are applied to high hazard industries, about which society has particular concerns'. The goal-setting framework make duty-holders think for themselves about hazards, risks and controls and in this context 'permissioning regimes define elements of the management arrangements required'.

The 2001 report states that regulators in a safety case system must be resourced 'to carry out searching audits of elements of the safety management system which require ongoing activity, such as incident reporting systems and management of change requirements'. It also restates that there is a 'tension between regulation and industry facilitation, on the basis that there is a conflict of interest arising if one organisation is responsible for both aspects'. This remains an issue in 2009 as is the potential conflict if a regulator investigates its own performance in the event of a significant or major accident or incident. It also remains an issue for Western Australia with the current assignment of responsibilities to DMP.

The 2001 report reinforces the importance of workforce understanding and involvement in a safety case if risk is to be properly managed and continuous improvement is to occur. It suggests that major accidents occur because hazards have not been identified or controls that were supposed to be in place were not operating as intended. (Underestimation of risk may be considered an allied or further causal factor.) Regulatory effectiveness also requires systems that are as simple as possible to operate and administer and where unnecessary duplication is minimised. The IRT stated that attention needs to be given to the interaction between Commonwealth and State legislation and to clarify the unclear and undefined role of the Designated Authorities with the best solution the development of a single national petroleum safety authority but the issue of whether health, safety and the environment should be integrated under one set of regulations and one reporting framework was an issue of administrative efficiency with only a second order effect on safety. The IRT stated that performance standards[178] are an important tool in verifying that the design assumptions (and the risk figures that flow from them) remain valid over time, but that the Australian regime was not doing this well. Further, the IRT believed that while there was no concrete evidence of serious reductions in safety as a result of cost pressures, the potential was there.

Industry also noted that the same lack of regulatory clarity which impacts efficiency and cost effectiveness in the offshore context can result in attention being distracted from the main intent of preventing major accident events. As a result, the 2001 report found a 'clear requirement exists to improve the interfaces between State and Commonwealth legislation applicable to the offshore industry'. The Commonwealth proposed that 'an independent statutory authority be developed that will regulate both Commonwealth and State petroleum safety activities'.

The 2001 report also noted the absence of sufficiently robust national safety performance data or data analysis capability for the Commonwealth to determine the level of offshore risk and the desirability of a standardised suite of leading and lagging indicators that could be benchmarked across companies, countries and regulators. Examples of possible measures in the suite were:

- measures of near misses that could have resulted in a major accident event;
- measures of perceptions (attitudes) towards the commitment of the organisation to safety;
- measures of activities which are being undertaken to identify and minimise risk (audits and close out actions); and
- existing lagging indicators (fatalities, LTIFR or total medical treatments for injuries).

178 The IRT stated that performance standards are criteria established by the operator that indicate, particularly in respect of safety critical systems, what has to be done, and at what frequency, to preserve the risk figures assumed in the design.

2003 review

The June 2003 *Report of the Independent Review Team* on the implementation of the 2000 IRT recommendation to establish a National Offshore Petroleum Safety Authority comprised the same team of Messrs Magne Ognedal and Odd Bjerre Finnestad from Norway's safety regulator and Mr Ed Spence of Integral Safety Ltd. The 2003 report cites the principles for offshore industry regulation agreed on 4 March 2002 by the Ministerial Council for Mineral and Petroleum Resources (MCMPR):

1. *An enhanced and continuing improvement of safety outcomes in the Australian offshore petroleum industry is a priority for Governments, industry and the workforce.*
2. *A consistent national approach to offshore safety regulation in both Commonwealth and State/NT waters is essential for the most cost-effective delivery of safety outcomes in the offshore petroleum industry.*
3. *The safety case approach is the most appropriate form of regulation for the offshore petroleum industry to deliver world-class safety.*
4. *The legislative framework must be clear and enforceable to ensure safety regulation motivates operators to discharge their responsibilities for safety.*
5. *The regulator must demonstrate an independent approach in implementing its legislative responsibilities and in its dealings with industry. The structure and governance of the regulatory agency must promote independence, transparency and openness.*
6. *The regulator must employ competent and experienced personnel to guarantee effective regulation of the offshore petroleum industry's activities and operations.*
7. *The administration of the safety regulator must deliver effective safety outcomes at efficient cost to industry.*
8. *Under the safety case regime, the industry and its workforce must be empowered to identify and report potential hazards and to implement appropriate control measures.*
9. *Approval processes in safety, titles, environment and resource management must be streamlined and dovetailed to ensure no undue delay to project development in the offshore petroleum industry.*

By the end of their review, the 2003 IRT still had three significant concerns with respect to the people resources, indeterminate scope, and unknown size and structure of NOPSA. The 2003 IRT noted APPEA's 'opinion that transportation pipelines from installations to shore should be NOPSA's responsibilities as long as they are in water, ie they reach land (terminals)'. Further, among other things, the National Oil and Gas Safety Advisory Committee emphasised that 'the interface between the PSLA and the Navigation Act is a grey area' and that 'Barrow Island needs to be properly sorted out. We cannot be under three regulators of the same issues ... NOPSA should regulate all waters and islands (and) be responsible for all pipelines in water'. The 2003 IRT also reported that 'All DAs agreed that transportation pipelines in water to the shoreline or pig receiver, should be the responsibility of NOPSA'.

2008 review

The March 2008 IRT included Magne Ognedal (again assisted by Mr Odd Bjerre Finnestad) Director General of Norway's PSA, Australian major hazards consultant, Dr Derek Griffiths, and Mr Bruce Lake Managing Director of Vermilion Oil and Gas Australia Pty Ltd and a former senior executive of Apache Energy Ltd in Perth.

The Review Team's main conclusion was that: 'NOPSA has made good progress in building a safety regulatory regime and authority of world class calibre, and, as expected there are still some aspects of the regime that can be improved on to achieve best practice regulation.'

Further the IRT concludes that 'NOPSA has addressed all aspects outlined by the Barrel Report for the common essential elements of Safety Case administrative systems. The two main recommendations of the 2000 Review, that the current Australian Commonwealth Safety Case regime framework of legal documents is revised and implementation of the Safety Case regime's regulatory system be restructured, have been implemented. The principles laid down in the Ministerial Council for Mineral and Petroleum Resources (MCMPR) are to a large extent fulfilled, but compliance with principles four, six and nine can be improved upon to enhance the delivery of safety outcomes in accordance with principle 7'.

Most aspects of the 2008 IRT report are of relevance to the current Inquiry and the panel is broadly supportive of most recommendations made by the 2008 Review of NOPSA with a number of additions

Annex 20: Leading and lagging indicators for the upstream petroleum sector

While there is an established consensus on a number of lagging indicators used in the offshore petroleum industry, the specification of leading indicators is much more problematic. A positive safety culture will encompass both personal (OHS) and process (MAE) safety and separate leading and lagging indicators are normally required for each. In both cases, it is important to choose indicators that are as simple and understandable as possible, use data already generated if possible, and to seek standard measures that allow meaningful comparison across the industry and across time. Monitoring of such indicators can drive positive safety change. Because OHS indicators are better developed, the focus below is on process safety and indicators that may be indicative of developing hazards that could lead to a major accident event. Good indicators will allow operators, industry bodies and regulators to better target safety 'hot spots', including through education, training and safety promotion.

Examples of measures that can be developed into leading indicators

- Safety considerations in organisational structure and hierarchy (eg to reduce middle management filtering of unwanted 'bad news' on safety)
- Staffing of key safety/technical positions (ie per cent filled, competency levels)
- MAE/emergency training (per cent personnel trained, level of training, recency)

- management training in system safety and process safety (per cent, level and recency)
- management attention to incident data and learning from MAEs across the corporation and from others in like industries
- incentive structures for management that include safety as well as commercial objectives
- workforce input to continuous review of the safety case (monthly number of suggestions and percentage of workforce making suggestions annually)
- average time to resolve process safety suggestions
- level of confidential reporting of safety issues by workforce (monthly number of reports an trends in reporting)
- incidents and 'near misses' reported monthly (although an improving safety culture will promote more reporting so numbers alone do not imply problems)
- percentage of relevant process standards and their revisions reviewed annually
- use of audits and internal investigation to establish root causes of safety matters
- open recommendations involving safety from audits, consultancies and investigations and percentage of completion of follow-up in relation to safety
- rate of improperly performed process 'line breaking' activities
- unannounced observation of work practices to assess conformance with best practice safety procedures
- senior management visits to facilities and discussion with frontline staff
- degree of implementation/conformance to policies & procedures that support the SMS
- relative frequency and emphasis of process safety/MAEs in management communications compared with cost, quality, production etc
- staff surveys of safety attitudes and perceptions across operators, facilities and time including with regard to management commitment to and leadership of safety.

Further examples of leading indicators are provided in the US Center for Chemical Process Safety's excellent 2007 book *Guidelines for Risk Based Process Safety*.

The London-based International Association of Oil and Gas Producers (OGP) has been working on leading indicators for many years but with limited consensus. In Australia, the Australian Petroleum Production and Exploration Association (APPEA) is currently doing so in liaison with OGP. APPEA is trialling three key leading indicators in the second and third quarters of 2008–09. These are: the numbers of safety tours conducted by senior management per 100,000 hours worked; numbers of high potential incidents reported per million hours worked; and the percentage of identified improvement/corrective actions arising out of planned audits closed off within specified timeframes.

Many mature best practice regulators such as Norway's PSA also continue to seek a meaningful suite of leading indicators.

Lagging indicators

APPEA publishes a set of indicators which measure the performance of the oil and gas industry in Australia. Important lagging indicators are the set agreed by the International Regulators Forum (IRF) that includes NOPSA. NOPSA has in 2009 published its *Offshore Health and Safety Performance Report 2007–08 (with summary data from 2005–06 and 2006–07): Statistics, Trends and Observations of Health and Safety in the Australian Offshore Petroleum Industry.* This is a significant step forward in benchmarking Australian safety.

Norway's Petroleum Safety Authority (PSA) has an annual *Risk Levels in the Petroleum Industry* publication in which quantitative indicators measure developments for 'serious incidents and near-misses', while the PSA applies qualitative methods in a bid to identify possible models that can explain the trends. The PSA uses a biennial questionnaire-based poll among all employees on offshore installations and at land-based plants to provide an additional dimension.

We were also impressed by the UK HSE's Offshore Division work on asset integrity and its November 2007 publication *Key Programme 3, Asset Integrity Programme.* The HSE also publishes very comprehensive annual data. The very detailed annual planning by the Dutch regulator (SODM) which is based on a matrix of risk-based indicators was also commendable.

Annex 21: Use of standards in the Australian safety case regime for upstream petroleum regulation

Introduction[179]

Standards can take a range of forms. For the context of this discussion, a standard is a specific, industry-recognised, published document which sets out specifications and procedures designed to ensure that a material, product or method of service is fit for its purpose and consistently performs in the way it was intended.

Australian Standard® branded Standards are developed by Standards Australia following the organisation's standards developments process involving voluntary participation from relevant industry, government, community and other interested parties via technical committees. Australian Standards are living documents that are regularly reviewed to allow for research, changes and advancements in community expectations, technical, legal and environmental factors.

Australian Standards are voluntary documents offering a mechanism for self-regulation with which compliance is not mandatory unless the Standard is incorporated into law by government or called up in contractual arrangements.

179 This annex has been prepared with the assistance of Standards Australia.

For the offshore safety case regime in Australia, the MOSOF regulations under the OPGGSA state:

> *The safety case for a facility must specify all Australian and international standards that have been applied, or will be applied, in relation to the facility or plant used on or in connection with the facility for the relevant stage or stages in the life of the facility for which the safety case is submitted.*

All standards listed in the safety case then become legal requirements with which the operator must comply.

Where a standard is revised, industry has advised that it considers good practice requires that the operator undertake a risk assessment to determine the impact of any significant changes that result from this revision, and amended its practices accordingly to continue to ensure risk is reduced to ALARP. Further, MOSOF regulations require an operator to revise their safety case in light of a significant change in circumstances which would include standards revisions.[180]

Standards development

The Federal Government recognises Standards Australia as the nation's peak, non-government Standards body. Standards Australia is therefore the leader in the development of Australian Standards. Standards Australia prepares voluntary, technical and commercial Standards for use in Australia and accredits other Standards Development Organisations via the Accreditation Board for Standards Development Organisations, an independent entity that is part of the Standards Australia group.

Standards are developed in consultation with key stakeholders, including industry, academia and government regulatory agencies, in order to codify industry good practice. Participation of industry in this process is usually on a volunteer basis, with companies bearing the cost of time spent on the process. The benefits of participating in these fora are well recognised by industry as a learning and information-sharing opportunity for the company.

Standards Australia facilitates the development of Australian Standards by working with Government, industry and the community. Australian Standards set specifications and guidelines to ensure the quality, safety, reliability and consistency of products and services. Every effort is made by Committees to achieve consensus and

180 S34 'Revision of a safety case because of a change of circumstances or operations' *Petroleum (Submerged Lands) (Management of Safety on Offshore Facility) Regulations 1998*

ensure that interests of all stakeholders are considered during the development of an Australian Standard.

For any given Standard, the decision on whether to adopt an International Standard normally rests with the appropriate standards technical committees. If an International Standard is identified that fully satisfied local requirements, an assessment needs to be made as to the value of having a local adoption rather than allowing the International Standard to be used directly in the marketplace.

Once an Australian Standard has been aligned with its international counterpart, Standards Australia emphasises the importance of ensuring that amendments to, and revisions of, the International standard are mirrored int he local Standard so that international equivalence is maintained. Similarly, the effect on international equivalence needs to be considered before any local amendment to an adopted Standard is made.

The role of the regulator with respect to standards

In the Australian safety case regime, regulators accept and audit the systems and processes within the safety case. Regulators do not verify each specific detail of a safety case nor, by extension, the operator's adherence to specific standards applied within that safety case. Regulators should, however, review the applicability of the standards applied in a safety case to ensure the operator demonstrates good practice. NOPSA has indicated that it addresses the applicability of standards through a validation process defined in the MOSOF regulations.

Depending on its internal policies the regulator may participate in, the development of standards. Standards Australia Committee ME-038, the committee responsible for developing the Australian Standard AS 2885 for gas and liquid petroleum pipelines, includes participants from the Western Australian Department of Mines and Petroleum (DMP), the South Australian Department of Primary Industries and Resources (PIRSA), and Energy Safe Victoria (ESV).[181]

181 AS 2885.0-2008, *Australian Standard: Pipelines – Gas and liquid petroleum part 0: General requirements*, SAI Global (2008)

National and international pipeline standards

Of the standards applicable to the upstream petroleum industry, the Inquiry has identified six standards that would be particularly applicable to upstream petroleum pipeline regulation:

International	ISO 13623	Petroleum and natural gas industries – Pipeline transportation systems.
European	BS EN 14161[182]	Petroleum and natural gas industries. Pipeline transportation systems.
Canadian	CSA-Z662	Oil and gas pipeline systems.
Norwegian	DNV OS F101	Offshore standard – Submarine pipeline systems
Australian	AS 2312	Guide to the protection of structural steel against atmospheric corrosion by use of protective coatings petroleum
Australian	AS 2832	Cathodic protection of metals
Australian	AS 2885	Pipelines – Gas and liquid petroleum

These standards, in particular AS 2885, are further outlined below.

Standards applied to Varanus Island and the 12 inch Sales Gas Line

Apache Energy Limited's Varanus Hub Safety Case (SC) and Pipeline Management Plan (PMP) reference a plethora of international and national (including Australian) standards. The SC alone lists 130 codes and standards for the Varanus Island Hub safety case while the PMP lists ten standards. Of the standards identified above, the SC and PMP refer only to AS 2885, AS 2832 and DNV OS F101. The facilities description for the PMP nominates the standard(s) that apply to each pipeline, and the SC employs a 'tick-box' matrix for each standard to identify which facilities they apply to. While this information identifies relevant standards, and identifies where they should be applied, it does not demonstrate the appropriateness of these standards for the facilities in question.

182 *This standard replaced British standard BS 8010 in 2003. The British Standards Institute continues to produce a code of practice BS PD 8010: Code of practice for steel pipelines on land and subsea pipelines.*

For the 12 inch SGL, the PMP only specifies Part 1 (Design and Construction) of AS 2885 for adherence, thereby excluding sections of the standard that are specific to operations and maintenance as well as the offshore submarine section of the pipeline.[183]

Regulator access to standards

NOPSA has an information system and Information Team that arrange ready access for relevant documentation, including standards for NOPSA inspectors where identified as appropriate or necessary for their tasks.

The Information Team within NOPSA holds subscriptions to several standards publishers, including SAI Global, the publisher of all Australian standards. Of the seven standards listed above, NOPSA's current subscriptions to SAI Global and others includes ongoing online access to AS 2885 only.

NOPSA could access ISO 13623, CSA-Z662, AS 2832.1 and DNV OS F-101 but has not upgraded the relevant subscriptions in order to do so. NOPSA also does not currently have a subscription that would enable access to BS EN 14161. However, it is possible that individual inspectors have access to various standards individually where they are not held centrally within the organisation.

DMP has valid subscriptions to the key Australian Standards relating to pipelines, including all parts of AS 2885, AS 2312, and AS 2832. The Department does not currently have access to international or other national standards.

Outlines: national and international standards

ISO 13623: Petroleum and natural gas industries – Pipeline transportation systems

This is the international standard for pipeline transportation systems. It specifies requirements and gives recommendations for the design, materials, construction, testing, operation, maintenance and abandonment of pipeline systems used for transportation in the petroleum and natural gas industries.

The standard applies to pipeline systems on land and offshore. It describes the functional requirements of pipeline systems

183 Facilities description, Apache Energy Limited Operational Pipeline Management Plan (2008)

and provides a basis for their safe design, construction, testing, operation, maintenance and abandonment.

A new version of this standard is due for release in 2009. The Inquiry understands that this revision includes an important change to consider pipelines as systems rather than individual pipes.[184]

Apache does not reference this standard in its Varanus Island Hub SC or PMP. Neither NOPSA nor DMP have access to this standard.

BS EN 14161: Petroleum and natural gas industries. Pipeline transportation systems

This European standard replaced British standard BS 8010 in 2003. It specifies requirements and gives recommendations for the design, materials, construction, testing, operation, maintenance and abandonment of pipeline systems used for transportation in the petroleum and natural gas industries.

It applies to pipeline systems on land and offshore, connecting wells, production plants, process plants, refineries and storage facilities, including any section of a pipeline constructed within the boundaries of such facilities for the purpose of its connection.

Although this standard supersedes BS 8010, the British Standards Institute continues to provide guidance to industry through PD 8010: Code of Practice for Steel Pipelines. This Code has three parts:

- PD 8010-1: Steel pipelines on land
- PD 8010-2: Subsea pipelines
- PD 8010-3: Steel pipelines on land.

  Guide to the application of pipeline risk assessment to proposed developments in the vicinity of major accident hazard pipelines containing flammables. Supplement to PD 8010-1.

Apache does not reference this standard, its predecessor BS 8010 or PD 8010 in its Varanus Island Hub SC or PMP. Neither NOPSA nor DMP have access to this standard.

CSA-Z662: Oil and gas pipeline systems

This Canadian standard is designed as the ‘ultimate reference tool’, providing up-to-date requirements on the design, construction operation and maintenance of oil and gas pipeline systems, including those that convey liquid fuels and natural gas products.[185]

184 David Willis, BSI/RSK Group, *Oil & Gas Pipeline Integrity Conference, Amsterdam* 16/02/2009

185 *Canadian Standards Association*: <www.csa.ca>, accessed on 19 March 2009

Apache does not reference this standard in its Varanus Island Hub SC or PMP. Neither NOPSA nor DMP have access to this standard.

DNV OS F-101 Offshore standard – Submarine pipeline systems

This Norwegian standard describes the functional requirements of subsea pipeline systems and provides a basis for their safe design, construction, testing, operation, maintenance and abandonment. A subsea pipeline system is defined as extending to the first weld beyond:

- the first valve, flange or connection above water on platform or floater
- the connection point to the subsea installation
- the first valve, flange, connection or insulation joint at a landfall unless otherwise specified by onshore legislation.

The Standard comprises thirteen sections and six appendices covering design, construction, installation, operation, inspection and repair of subsea pipelines.

It also includes specific sections on corrosion control in design and coating/cathodic protection manufacture and installation as well as integrity management processes as they pertain to corrosion. It does not provide specific requirements for cathodic protection of pipelines at the shore crossing (from the low water to the high water mark). Standards Australia has noted that this is not unusual, as other codes do not have such specific requirements either.

It is worth noting that the superseded 2000 version of this Standard (the Standard was revised in 2007) specifically excluded the shore-crossing area in its section on corrosion protection measures, creating a gap with respect to corrosion protection under the Standard. The current version of the Standard covers corrosion protection requirements up to the limit of the Standard as defined above.

The Standard also includes reference to several 'Recommended Practices', which are guidance documents developed to sit alongside standards. This includes *DNV-RP-F103: Cathodic Protection of submarine pipelines by galvanic anodes*.

Apache references this Standard in its Varanus Island Hub SC and PMP, but not in relation to the 12 inch SGL. Neither NOPSA nor DMP have access to this standard.

AS 2832: Cathodic protection of metals

Part one of AS 2832 is specific to 'requirements for the cathodic protection of buried or submerged metallic pipes and cables.'

It defines the two types of cathodic protection available as:

(a) Galvanic anode systems, which employ metallic anodes that are consumed to provide the source of direct current for protection of the structure. The driving voltage for the protective current comes from the natural potential difference that exists between the structure and a second metal (the galvanic anode).

(b) Impressed current systems, in which the driving voltage for the protective current between the structure and the anode is supplied by an external direct current power source.

Apache references this Standard in its Varanus Island Hub safety case, but not the PMP. DMP has access to this Standard but NOPSA does not.

AS 2312: Guide to the protection of structural steel against atmospheric corrosion by use of protective coatings

This Standard provides information on the modes of corrosion and protective coatings appropriate to a range of atmospheric corrosive environments. It states:

> *The Standard covers the protection of structural steel work against interior and exterior atmospheric corrosion and also the protection of items of equipment manufactured from steel which are exposed to exterior atmospheric conditions.*
>
> *The Standard covers, to a limited extent, the protection of steel work which is completely immersed in water or buried in soil, or which is subject to atmospheres severely contaminated with acidic or other chemical vapours such as may be encountered in some chemical manufacturing plants, and also the protection of ships.*

Standards Australia advises that the tables for selection of coatings in this Standard include categories for 'sustained exposure' and 'intermittent splashes' which would be appropriate for a shore-crossing area.

Apache does not reference this Standard in its Varanus Island Hub safety case or PMP. DMP has access to this standard but it is not known whether NOPSA has access to this standard.

AS 2885: Pipelines – Gas and liquid petroleum

This Australian Standard describes requirements for pipelines, including materials, design, construction, installation, inspection, testing, operating, and maintenance. It comprises six parts:

Part 0 (2008): General Requirements

Part 1 (2007): Design and Construction

Part 2 (2007): Welding

Part 3 (2001): Operation and Maintenance

Part 4 (2003): Offshore submarine pipeline systems

Part 5 (2002): Field pressure testing.

NOPSA and DMP have ongoing subscriptions to all parts of this Standard, and Apache's safety case and PMP reference this Standard.

However, the PMP for the 12 inch SGL specifies AS 2885.1 (Part 1) only as the relevant standard for adherence. In addition, it is worth noting that AS:2885 Part 4 (offshore submarine pipeline systems) defers entirely to a Norwegian standard: *DNV OS-F101: Offshore Standard – Submarine Pipeline Systems*. This requires the operator (and regulators) to buy and comply with this separate standard in order to fully comply with AS 2885.

It should be noted that this Standard is largely written with onshore pipelines in mind, with the exception of Part 4 which is specific to offshore (submarine) pipeline systems.

Further information on these parts is provided below. This information includes comment on:

- differences between the corrosion mitigation sections of the current and the 1987 edition of AS 2885 (in force when the 12 inch SGL was installed);
- potential deficiencies in risk assessment process in AS 2885; and
- the deferral to DNV OS-F101 in AS 2885.4.
  - *AS 2885:1 – Design and Construction*

This part describes requirements for the design and construction of a pipeline, but also includes:

A) a description of corrosion mitigation methods; and

B) an outline of the risk assessment process for managing safety and integrity of a pipeline over its lifetime.

A. Corrosion mitigation methods

Section 8 of AS 2885.1 describes various corrosion mitigation methods for both internal and external corrosion. This part is worthy of note as it has changed in content over time from the 1987 edition of AS 2885 which was in force at the time that the 12 inch SGL was installed.

Both editions of AS 2885 require the operator to test the efficacy of corrosion mitigation measures. AS 2885-1987 differs in that it includes some prescriptive measures stipulating the methodology to be followed and time intervals to be adhered to in this testing. The current edition, on the other hand, does not include prescription, opting instead to refer the operator to risk-based decision making for this testing.

The removal of this prescriptive condition should prompt the operator to reassess its risk assessment regarding corrosion mitigation and, from this assessment determine the ongoing corrosion mitigation testing required for their operations to achieve ALARP. This is both good industry practice and a requirement in Australia under the MOSOF regulations.

B. Risk assessment processes

The risk assessment process outlined in AS 2885.1 is best described through guidance developed by APIA for Standards Australia. This guidance notes that the AS 2885 risk assessment philosophy differs from the conventional risk analysis in which risks are evaluated by aggregating a number of different types of events.

The guidance summarises the AS 2885 procedure as follows:

- Identify threats to the integrity of a pipeline and the consequence of a loss of integrity of a pipeline. Each threat is considered in relation to the location or range of locations relevant to the threat
- Apply the design and operation/maintenance requirements of AS 2885 to reduce (to the level of accepted risk) threats which can be dealt with by design/procedures
- Evaluate the remaining threats for their potential to cause loss of integrity to the pipeline threats which would result in loss of integrity are then identified as hazardous events
- Evaluate each hazardous event by the allocation of a qualitative measure of its frequency and its consequence. Derive a risk ranking from the combined resultant frequency and severity measures
- Implement risk management actions appropriate to the risk ranking of the hazardous event.

While the above procedure seems adequate, it is important to note three key features of AS 2885.1 that could compromise this risk assessment process:

1. In describing potential threats to a pipeline, AS 2885 describes corrosion as a threat that exists 'over the entire length of the pipeline', indicating that a location analysis may not be required, and that the shore crossing area may not need any particular attention in this regard.
    - The APIA Guidance confirms this by stating: 'Most threats are location-specific. However, some threats, such as corrosion, apply uniformly over extended lengths and are treated as such.'
2. The process to identify hazardous events notes that a threat should be further analysed 'where controls may not prevent failure for a particular threat.' The context of this statement, and detailed information on external corrosion mitigation within AS 2885, mean that an operator may interpret this statement in such a way that a full risk assessment for pipeline integrity at a shore crossing may not occur.
3. Where a location analysis is performed, locations are classified into a primary (high consequence) or secondary (low consequence) class. The class impacts the consequence and threat analysis of the pipeline. The secondary location class includes:
    - Land defined as a common infrastructure corridor (CIC), which includes where several pipelines are located within the same easement.
    - Land that is continuously or occasionally inundated with water (W).

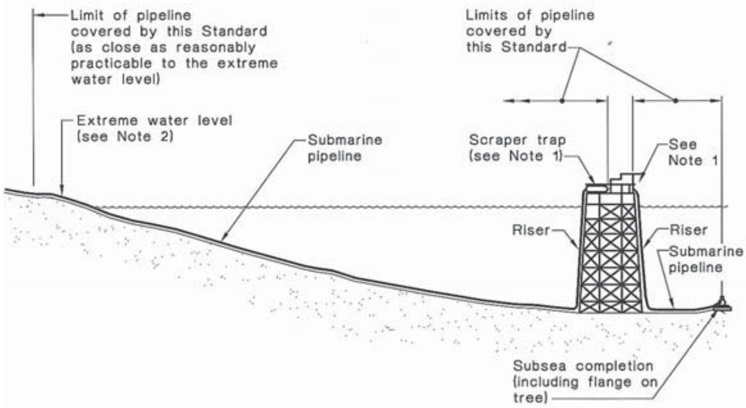
While it is true that these locations pose less of a threat to human life, the threat to integrity of the pipeline is certainly not 'low.'

- *AS 2885:4 – Offshore submarine pipeline systems*

AS 2885 Part 4 defines the scope of offshore pipeline systems as per the figure below:[186]

186 *Australian Standard AS 2885:Part 4* – Offshore Submarine Pipeline Systems

Figure 13: Offshore pipeline systems' scope as per AS 2885.4



NOTES:

1 Where there is no scraper trap, the Standard's limit shall be the riser and including the emergency shutdown (ESD) value.

2 Extreme water level is that water level resulting from the design environmental event being a combination of tide, storm surge and wave run-up.

FIGURE 1.1 APPLICATION LIMITS—SUBSEA COMPLETION TO PLATFORM AND PLATFORM TO SHORE
(The arrangement shown is typical only)

The Standard then specifies that:

> *All requirements for offshore submarine pipeline systems with respect to safety, design, materials, fabrication, installation, testing, commissioning, operation, maintenance, requalification and abandonment shall be in accordance with the latest edition of DNV OS-F101. The requirements of AS 2885.1, AS 2885.2, AS 2885.3 and AS 2885.5 are not applicable.*

AS 2885.4 also specifies that:

> *Should DNV OS-F101 be silent with regard to any aspect of the scope then, subject to Clause 6, guidance shall be sought in the first instance from other relevant Australian Standards.*

This clause was especially relevant to the superseded (2000) version of DNV OS-F101 as that standard excluded 'onshore sections at any landfall of pipelines.' The exclusion prompted the re-application of AS 2885 (Parts 1, 2, 3 and 5) for corrosion protection measures for the shore crossing area. However, as these parts of AS 2885 were not written with the shore crossing area (below the extreme high water mark) in mind, the corrosion protection measures mentioned in the Standard may not have been ideal for this area, presenting a gap in its coverage.

The revised 2007 version of DNV-OS-F101 has been expanded to include corrosion protection measures across the entire scope of the Standard, including the shore crossing area of the pipeline route.

Annex 22: Buncefield Inquiry in the UK, and Seveso I and II in Europe

Buncefield

On 11 December 2005 a petrol storage tank was overfilled at a large tank farm at Buncefield in Hemel Hempstead, England, and the uncontained vapour cloud ignited causing a massive explosion. Subsequent fires destroyed 23 tanks in the farm, which was a major source of jet fuel for Heathrow airport. Economic losses as a result totalled about GBP 1 billion.

The major incident was investigated on behalf of the regulator and 'competent authority' (the UK Health and Safety Executive or HSE) by a six member board headed by Lord Newton of Braintree and included a secretariat drawn from the HSE and a number of external experts. The three-year inquiry involved 83,000 staff hours and cost GBP 15 million, leading to a final report in late 2008. Interim reports and recommendations were released throughout the inquiry and focussed on technical safety issues for tank farms and particularly in the context of location of highly hazardous facilities near high density urban areas.

The investigation was undertaken through the regulator and explicitly did not seek to assess any regulatory failure that may have contributed to the incident. The final report states that:

> *The major constraint on such openness has been the need to avoid prejudice to the criminal investigation or any person who may affected thereby. We have published information on what happened and how but have been cautiously circumspect in suggesting why the incident occurred.*

The final report argues that:

> *It is rightly the task of those conducting the criminal investigation to establish whether any acts or omissions of HSE and/or the Environmental Agency had any bearing on the*

Buncefield incident. The Board has not sought to make any determination of its own in this regard.

In contrast with major NTSB, TSB, CSB and ATSB systemic investigations, not seeking to establish 'why' is a very serious omission – the lack of detailed organisational analysis of the safety culture of companies that were involved in the incident and of any role by the regulator, has led to a report that is much less comprehensive and valuable for future safety than it could have been. The omission is all the more glaring given that the final Buncefield report extensively cites reports on the 2005 Texas City refinery explosion that do include much broader organisational analysis.

The problems with Buncefield truncating its investigation because of the HSE regulatory and blame focus furthers the case for such an investigation to be managed by an appropriately resourced and legislatively empowered no-blame safety investigator.

The Buncefield Inquiry reports are certainly not without merit, and the discussion of high reliability organisations (HROs) and requirements for a stronger safety culture generally and for more focus on integrity, in particular, are among their many strengths. But in future safety terms there was clearly an opportunity lost.

Seveso I and II in Europe

A chemical plant accident on 10 July 1976 on the outskirts of a small town 20 km north of Milan led to a dioxin cloud over a densely populated area about 6 km long and 1km wide that included the municipality of Seveso with up to 2,000 people treated for dioxin poisoning. It prompted the adoption of legislation aimed at the prevention and control of such accidents and the 1982 EU Directive 82/501/EEC known as the Seveso Directive.

On 9 December 1996 this was replaced by the so called Seveso II EU Council Directive 96/82/EC which includes general and specific obligations, the need for information to and consultation with the public, safety management systems, incident reporting, inspections, land use planning, and emergency plans – many of the areas dealt with in the recent Buncefield reports. Seveso II excludes the transportation of dangerous substances by pipeline. The Seveso II Directive has in turn been extended by Directive 2003/105/EC which among other matters picks up new research on both carcinogens and impacts on the environment. The Seveso Directives have included increasing levels of prescription. This is contrast to the Safety Case objective-based or goal setting approach adopted since the Cullen Inquiry into Piper Alpha which is more in keeping with the 1972 Robens approach to OHS in the UK and Australia. Buncefield seems to be moving the UK towards more prescription for high hazard facilities in populated areas in common with much of the rest of Europe.

The *F-Seveso: study of the effectiveness of the Seveso II Directive Final Report* was completed on 29 August 2008. It utilised survey and interview data from targeted high hazard industry sectors in 8 EU member states as well as independent analysis.

The report found that all targeted groups thought that the implementation of the requirements of the Seveso II Directive has led to a recognizably higher level of safety in comparison with non Seveso establishments. Respondents agreed that the approach of the Seveso II Directive is well-suited to prevent major accidents and mitigate their consequences and that the requirements are adequate to meet these aims, and valuably complement the other directives dealing with safety related issues, like Occupational Health and Safety and Integrated Pollution and Prevention Control (IPPC) Directives.

The 'two tier approach, implementing the proportionality principle', was recognised as appropriate. However, the great majority of the respondents indicated that the implementation of the Seveso II Directive was not uniform within Europe and even in a given country. This was seen to represent a problem, especially for multi-national companies operating in several Member States because most of them have internal safety standards or approach.

A report recommendation is to extend

> *the obligation for lower tier establishments to prepare a Safety Report (or at least an identification of major accident scenarios) and the provision of a Safety Management System.*

Annex 23: Irish Government-commissioned independent safety review of proposed Corrib gas pipeline, January 2006

The Corrib gas field off the west coast of Ireland was developed by a consortium which sought approval from the Irish Government to bring a high pressure gas pipeline onshore in a populated area. Ireland's Minister for Communications, Marine and Natural Resources commissioned an independent safety review of the onshore section of the proposed pipeline by Drs Michael Acton and Robert Andrews of Advantica based in Leicestershire. The draft Advantica report was submitted to the consortium and others for review prior to finalisation on 17 January 2006.

The report noted that while internationally acceptable quantitative risk assessment (QRA) techniques had been used by the consortium to evaluate risk to the public, there was no formal framework in Ireland for decision on the acceptability of different levels of risk which was desirable to ensure consistency of decision making. It was found that the consortium proponents had not provided sufficient evidence that the integrity of the pipeline would be maintained to a sufficiently high standard throughout its life and the need for a formal integrity management plan and system was highlighted. It was noted that section 13 of British Standard PD8010-1 covered basic requirements and that ideally such an integrity management system should be used from the start of the project.

In terms of preventing external corrosion, as coatings are not 100 per cent effective, cathodic protection (CP) systems were used with an impressed current system on land and a sacrificial anode system subsea. An insulation joint where the pipe reaches land was considered best practice based on the standards DNV RP B401 and ISO/CD 15589-2 to enable more accurate polarised close interval potential surveys required to validate the CP, with test cables installed on both the onshore and offshore sides of the insulation joint.

While we do not necessarily endorse the detail, the independent review provides a good example of the need to assess carefully the complexities associated with pipeline corrosion protection and integrity management including in transitional areas like shore crossings. We see considerable merit where relevant, in having such specialist pipeline corrosion and integrity reviews, perhaps commissioned and paid for by the relevant government regulator rather than operators to reduce the possibility of conflict of interest. This would not preclude subsequent cost recovery from operators.

Annex 24: Relevant regulation and safety cases: US, UK, Netherlands, Norway

In order to inform our consideration of the Australian Safety Case (SC) regime, we explored the regulatory regime for safety and integrity management in the US, the UK, the Netherlands and Norway. Characteristics of the regimes and lessons applicable to the Australian regime are as follows.

United States

The Minerals Management Service (MMS) in the US Department of the Interior has regulatory responsibility for offshore oil and petroleum resources on the US outer continental shelf. They regulate all aspects of offshore resources including acreage release, resource management, environmental management, and integrity and safety management. The regulatory environment is primarily prescriptive, but an element of the management plans/safety case philosophy has, of necessity, been adopted to overcome the fast-moving nature of technology in the industry.

MMS has five inspection teams in the Gulf of Mexico and several others working across other regions. Each team consists of a manager, a drilling engineer, a production engineer, a workover engineer, an environmental regulator and a supervisory inspector. Overall, the organisation has around 50 offshore inspectors with two-three participating in each audit. Regulation requires audits to be carried out once per year per facility, however, the MMS is now transitioning to a more risk-based, rather than calendar-based, approach to auditing. MMS has designed a risk matrix based on the output of the facility, whether the facility is manned, and whether the operator is considered a ‘poor performer’. This approach is freeing up time to increase accident investigations, conduct more unannounced inspections and to perform 'blitz' inspections where the inspection team visits as many facilities as possible to inspect identified problem areas such as cranes. In addition, the MMS runs a performance review for each operator every year, investigating the operator's history of compliance, action on any issue raised following audits, accidents and incidents, and the safety and environmental management program as it relates to accidents and non-compliance concerns.

The MMS has a range of penalties available as enforcement tools. Inspectors in the field can order a 24 hour or seven day warning to correct an issue, a component shut in, or a facility shut in. The MMS can issue penalties of up to $35,000/day/violation for civil offences such as bypassing safety systems. At the extreme end of the scale, the MMS can pursue a criminal case with potentially very high penalties, such as a US$50m fine for flaring gas and falsifying records related to flaring, or can place the operator on probation at which point the company is not permitted to operate any facility. The MMS publishes financial penalties for safety breaches on its website and includes details about the incident.

United Kingdom

The Offshore Division of the Health and Safety Executive (HSE) is responsible for regulating safety of offshore facilities in the UK, while pipelines are regulated by the Onshore Division. This is undertaken through a safety case methodology developed following Lord Cullen's report on Piper Alpha. The regulatory approach has developed over time and now has a lower reliance on QRA than Cullen originally envisaged because it is difficult to quantify some qualitative risks. The organisation is now also moving away from just using ALARP and towards more legally definable and defensible requirements. The Division's focus is on major accident events (MAEs) as their experience suggests that companies with MAE risks under control generally have personnel safety covered as well.

The HSE aims, where resources allow, to carry out two structured visits to each facility each year noting that, if resources are restricted, larger facilities with more people are considered higher priority, as are poor performing companies and higher risk installations. Each audit team has a range of facilities for which it is responsible, both for auditing and for assessing the risk posed by the facilities. The Division has a range of technical specialists available, as well as operations and human and organisational factors specialists, reflecting their focus on management systems and culture.

The basic philosophy of the Offshore Division is one of enforcing good industry practice through a safety case methodology, and then using an educational, cooperative process with the companies to achieve incremental improvements in the 'good practice' benchmark. The Division has found big variations within and between companies, corporate memory loss, 'short termism' in management, lack of understanding of systems, huge problems with maintenance backlogs, and fundamental issues. Educating senior management and boards is an important response, as are more meaningful Key Performance Indicators. Ageing infrastructure and asset integrity is another key theme.

The Netherlands

Safety of offshore facilities in Dutch waters is managed by the State Supervision of Mines (SODM), an independent agency which reports to four Ministers, though with a primary reporting line to the Minister of Economic Affairs. SODM has delegated authority to monitor health and safety, incidents, environment and integrity and describes itself as the 'eyes and ears' of other agencies with marginal non-delegated authority for issues such as helicopters.

The Dutch Government exercises a high level of control over offshore development, partially through its 100 per cent state owned oil and gas company, EBN, which is a 40–50 per cent active partner is all offshore developments, and partly through its small fields policy which restricts extraction from the massive Groningen field in favour of maximising extraction from the available smaller fields which, between them, are equivalent to approximately one third of the Groningen resource.

Management of safety on offshore facilities is through a company Safety Management System, with a safety case then required for each facility. In order to avoid accepting any responsibility for safety on facilities, SODM does not accept or reject SMSs or SCs, but simply asks questions/requires additional information until satisfied that no further questions need to be raised. Under this approach, the company retains fulls 'ownership' of the SC. While SODM expects companies to collect data relevant to management of integrity and safety on the facility (eg through testing, monitoring etc), and to be able to produce it if required, the regulator is far less interested in the data itself than in the company's response to that data.

SODM audits facilities on the basis of the SC, the company's own annual monitoring plan, and on those risks which SODM has decided will form the focus of its audits for the year. We were very impressed with the logical and thorough matrix used to underpin SODM's prioritisation.

Norway

Norway manages the safety of onshore and offshore facilities through the Petroleum Safety Authority (PSA). The PSA is an independent regulatory authority which, through a broad definition of 'safety', ensures the adequate protection of human life and health, environment, facility integrity, assets and security of supply. The PSA has whole-of-chain responsibility to regulate safety across the whole spectrum of activities from drilling operations through to the refinery. In 2004 the PSA split from the Norwegian Petroleum Directorate (NPD), creating a clear delineation between 'safety' and industry development/resource management. The PSA works cooperatively with the NPD and other agencies but has the authority to override other considerations and halt development or production if it feels that safety has been compromised.

The Norwegian regulation uses a 'consents' system to regulate safety, whereby the PSA and an operator engage in extensive discussions prior to the operator seeking, and the PSA granting, a consent to operate. This consent to operate, which is the over-arching safety management document, includes the operator's current safety management system and a number of binding commitments specific to that facility. Within this system, there are minimum standards which the company must meet in order to gain consent; however, any commitments over and above the minimum become legal requirements for that operation. The PSA can seek further information prior to granting a consent, but restricts itself to the minimum information required to accurately assess the adequacy of the operators systems, based on the risk presented by the individual operator and the facility itself.

This approach continues through the auditing process during which the PSA is more interested in measuring the effectiveness of the safety management system than in the nuts and bolts of the operation – although it should be noted that the PSA has the authority to inspect every nut and bolt if it deems it necessary. Primarily, audits centre on an annual supervisory plan and are systems oriented/risk based rather than calendar based. This supervisory plan is an ambitious program which responds to a range of current factors including industry risk trends (in Norway and worldwide), PSA experience and the current focus of the Ministry. Overall, the PSA would expect to audit each facility once each year, but the frequency, focus and nature of the audit responds to the risk posed by that particular facility/operator.

The PSA has a 'step' approach to enforcement ranging from dialogue as the first step to removal of an operator's permission to operate in Norway, although this last step has never been used. The majority of issues are resolved through dialogue, perhaps due to the fact that orders (and the notification of an order which occurs 14 days prior to an order being issued) are published on the PSA website from which they are rapidly picked up by the media. The PSA has the option of a coercive fine, which they do not currently use as it implies a company can 'pay their way out of an issue' rather than deal with it. At the upper end of the 'steps', they can stop activity to maintain safety and they can prosecute, although this is a rare occurrence. Both the PSA and the companies prefer to manage issues through dialogue rather than resort to the other, more public, enforcement options.

Annex 25: Developments in, and lessons from, Victoria's safety case law and practice

Purpose of this annex

In this annex, we consider how the development of law and practice in Victoria in relation to safety cases for major hazard facilities may guide improvements in respect of safety cases in the offshore and WA petroleum and gas industries. We have undertaken this examination because the Victorian system is well developed and has been the subject of a number of useful reviews and studies. We also briefly consider some reviews and research that were prepared in other contexts but which support the approach taken in Victoria.

Background

Victoria has, by regulation, provided a safety case regime for major hazard facilities (MHFs) since 2000.[187] The background to the adoption of this form of 'permissioning' scheme is discussed in the 2004 Review of the *Victorian Occupational Health and Safety Act*[188] and need not be further considered here.

An MHF is defined in the Victorian regulations[189] as a facility. Under the definition, a facility is any building or other structure on land that

187 The Occupational Health and Safety (Major Hazard Facilities) Regulations took effect in June 2000. The requirements relating to MHFs and safety cases are now part 5.2 of chapter 5, Hazardous Industries, of the *Occupational Health and Safety Regulations 2007*. Further requirements are at Schedules 9 – 12 of the Regulations.

188 Maxwell, C, *Occupational Health and Safety Act Review*, State of Victoria, 2004, pp.145, 146.

189 Reg.1.1.5.

is a workplace at which prescribed materials[190] are present or likely to be present and:

- at which the quantity of such prescribed materials exceeds a specified level; or
- which the regulator has determined to be an MHF because a smaller amount of the prescribed materials is present, or is likely to be present, at the facility and the regulator considers that there is a potential for a major incident[191] to occur.

Under the regulations, a person cannot operate an MHF unless an MHF licence has been granted or the MHF has been registered.[192] Provision is made for licence fees.[193] An application for a licence must be accompanied by a copy of a safety case that conforms to the regulations, and by certain other information.[194] The safety case must contain specified information[195], including a summary of the Safety Management System (i.e., a documented comprehensive and integrated management system for all aspects of risk control measures adopted in relation to the MHF for the purposes of Part 5.2 of the Regulations).[196]

Forty-one MHFs were registered by Victorian WorkSafe as at October 2008.[197]

Reviews of the Victorian approach to safety cases

The Victorian Safety Case regime was evaluated in three studies published in 2004. Two were undertaken by WorkSafe and the third by an independent market research organisation. Haines and Phung (2009) recently undertook an independent examination of the regime. Details are given in the 'key to references' below.

WorkSafe has conducted a further evaluation of safety case submissions. This was undertaken in the context of the second round of reviewed and revised safety cases submitted as required

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190 Such materials are prescribed in Schedule 9. A reference to the quantity that is 'likely to be present' at the facility is defined by reg.5.2.3.

191 Under reg 1.1.5, a *major incident* is an 'uncontrolled incident' that involves the prescribed materials and which '... poses a serious and immediate risk to health and safety'.

192 Reg.5.2.34 and Part 6.

193 Reg. 6.1.23.

194 Regs 6.1.1 and 6.1.20

195 Reg.5.2.15

196 Reg.5.2.5

197 A list is available at <www.workcover.vic.gov.au>

by the 2007 regulations. We understand the results to be positive, showing improvements in terms of lower risk, better documentation, lower safety case costs and more positive responses from licence holders about their relationship with WorkSafe and its performance. As the evaluation is not publicly available, we do not use it for the purposes of our discussion of the Victorian experience, except to note that there appears to have been a process of ongoing improvements underpinned by the 2007 regulations and by a commitment to continuous improvement by WorkSafe and the Major Hazards Advisory Committee. That committee is established with members from industry and unions to provide independent advice to the Victorian WorkCover Authority.[198]

Key publicly available results are summarised in the following table. This is not a full exposition of the findings and recommendations. For a full understanding of the context, scope, content and methodology of each review, interested persons should refer to the original material.

For the table below, the key to references is:

A. WorkSafe Victoria, *Review Report on Safety Case Assessment 2002 to 2003, 2004*

B. WorkSafe Victoria, *Oversight and Safety Case Feedback Survey Report, 2004*

C. Sweeney Research, *Evaluation of Major Hazards Implementation, 2003*

D. Haines, F and Phung, C. P., *Thoughts, Feelings Action: Survey of Victorian Managers of Major Hazard Facilities*, National Research Centre for OHS Regulation, 2009

198 Maxwell (2004) commented on the role and work of the Major Hazards Advisory Committee, which was limited to reviewing the formulation and implementation of the major hazards regulatory framework. Maxwell (Report, p. 66, para 240) noted that the committee's role in OHS regulation was well defined by virtue of that limited focus and did not propose any change.

Relevant findings in recent evaluations of Victorian safety case regulation

Issue	Reference	Summary of findings
Structure and content of safety case	A.	The Safety Case should contain only necessary and relevant information. The information should be set out within a carefully considered structure, which makes evident the operator's basis for the required demonstrations of the safety case's adequacy and the linkages between the compliance activities.
Content and operation of a Safety Management System	A.	Many operators are likely to need to undertake significant additions or modifications to management systems in order to achieve compliance with MHF regulations. Even those operators that have mature major hazards management systems prior to undertaking a safety case may need to make modifications to comply with the regulations. WorkSafe's advice was to commence such work as early in the process as feasible. There are likely to be efficiency benefits from integrating systems for management of major hazards and processes for management of general OHS hazards. The overall management systems should reflect the resourcing and capacity at the local level to apply them. There must be effective systems for auditing, monitoring and review, to ensure that the systems comply with the requirements and are being implemented in practice.
Tripartite involvement	A.	MHF regulators should consider the ongoing role of consultation with key stakeholders post introduction of their regulations. Special consideration should be given to the seniority of membership and the breadth of representative organisations and expertise.

Issue	Reference	Summary of findings
Education, advice and guidance	A.	Regulators should ensure that their education, guidance and oversight activities address the full range of the operators' regulatory duties, and avoid overemphasis on any one duty. Where MHF Regulators wish to intensively oversight the operators' Safety Case development, they should put in place processes to ensure that consistent advice is given, so far as is practicable. Regulators should use the findings of Safety Case assessment to update the information and guidance that is provided to industry. In addition, Regulators should work with and encourage industry groups to contribute to the dissemination of examples of good Safety Case practice relevant to their members.
Assessment and verification	A.	Regulators should implement processes for desk-top assessment and on-site verification. If their regulatory regime includes a licence, then verification should precede the licence decision.
Licensing	A.	Where the regime includes a licence, a 'panel' approach (to discuss issues before the delegate makes a licensing decision) is helpful.
Problems identified by operators	B, C.	Lack of information about what the regulator required. Guidance notes were not available in a timely way and should be in clear and simple language. Guidance notes should be prepared in consultation with stakeholders. Advice from regulator's field staff was sometimes inconsistent, too legalistic and not provided early enough. Responsiveness was sometimes lacking.
What makes a successful safety case regime	D.	Effective regulation combined with adequately resourced, skilled and problem focused regulator.

Other relevant research findings

We have also considered some other research relating to safety cases that is relevant to safety case regimes and, in particular, research that is relevant to the findings of the Victorian-related reviews that are discussed above. In general, the outcomes of that research are consistent with or otherwise support the conclusions in the Victorian-related reviews.

The HSE commissioned a literature review in 2003 to collate and assess published views on UK safety case regimes.[199] Key findings in the published material that was examined in the review include the following:

a) while safety case regimes are seen as having an initial positive effect, they may have less impact over time unless treated as dynamic ('live');

b) the management approach of the enterprise concerned is an important determinant of whether the overall safety culture and communications improve;

c) for a safety case to have a positive cost/benefit ratio, it is important that it be a 'live' working document and not an end in itself.

The literature review was complemented by a number of interviews with persons with experience of safety case regimes. Some respondents criticised the workload inherent in preparing safety cases and questioned the value that was added by such regimes.

The review of the literature led to a number of recommendations, which are consistent with the research and studies referred to above. In particular, the review underscored the need to consider how to integrate safety management into business processes and decision-making more effectively. In addition, a positive and proactive relationship between the regulator and the regulated was a crucial factor in the effectiveness of a safety case regime. Action should also be taken '... to ensure costs are driven down and that the impact of the safety case remains high'.[200]

Hopkins and Wilkinson (2005), discussing the possibility of safety cases in the mining industry,[201] reflected on the role of inspectors. They noted that regulatory staff must have credibility with senior company staff if changes that have been identified as necessary

199 Vectra Group Ltd, *Literature Review on the Perceived Benefits and Disadvantages of UK Safety Case Regimes*, 2003

200 Ibid, p.5.

201 Hopkins, A and Wilkinson, P, *Safety Case Regulation for the Mining Industry*, National Research Centre for OHS Regulation, Working Paper 37, 2005.

are to be both accepted and made. In their view, knowledge is a key aspect of such credibility and accordingly at least some of the regulatory staff must have first-hand experience of the industry to be regulated.[202]

Gunningham (2007), in considering the suitability of a safety case regime in the mining industry, pointed to four issues to be addressed for such an approach to be viable for 'a wider group of enterprises than just OHS leaders'.[203] These were:

a) a regulator must provide incentives to induce an enterprise to take its safety case obligations seriously (e.g., effective enforcement, positive and negative financial incentives, public access to compliance information, and requiring the CEO of the enterprise to sign off key regulatory requirements);

b) institutionalising commitment to the safety case in the enterprise concerned by making the policy in the safety case integral to corporate objectives, standard operating procedures, individual responsibilities and reward systems;

c) ensuring that there was genuine worker participation in the safety case regime; and

d) having a skilled and effective regulator.

In the Regulatory Impact Statement prepared for WorkSafe Victoria for public comment on the then proposed *Occupational Health and Safety Regulations 2007* (Vic), Allen Consulting referred to various items of evidence supporting safety cases, including an estimate of the reduction of thirty to fifty per cent in risks associated with incidents and improvements in the control of major hazards under the then applicable regulations.[204]

Relevance for law and practice in the offshore and WA petroleum and gas industries

We consider that key lessons include the following:

a) the legislation should be clear and useful to those with responsibilities under it;

b) the legislation should also facilitate a process of ongoing safety improvement and entrench the continuous pursuit by

202 Ibid, pp.8,9.

203 Gunningham, N, *Mine Safety, Law Regulation Policy*, Federation Press, 2007, pp.76-78

204 Allen Consulting, Regulatory Impact Statement for the *Occupational Health and Safety Regulations 2007* (Vic), 'The Case for Regulatory Control', p.120

the obligation holders and other stakeholders of the safety objectives reflected in the relevant safety cases;

c) there should be effective and ongoing interaction between the regulator and the principal stakeholders (operators, industry associations and unions), including, for example, by the involvement of an expert advisory committee drawn from those stakeholders;

d) there should be periodic external examinations of the effectiveness of the regulator's performance and the effectiveness of the safety case regime;

e) inspectors (however described) should have recognised skills and be actively supported in their professional development;

f) the regulator should provide guidance to applicants for licences and licence holders, with periodic consideration of the views of stakeholders on the effectiveness of the guidance;

g) the regulator should be vigilant about ensuring that advice and guidance, however provided, are relevant, timely, clear and consistent;

h) such guidance should be developed through consultation with the stakeholders;

i) the workforce must be actively supported in understanding the safety case structure and use and effectively represented in its development the regulator must not only be prepared to take enforcement action where that is warranted, but the legal consequences of non-compliance must be meaningful;

j) KPIs should include leading indicators and allow valid comparison within and across industries.

We note that the findings and recommendations of the 2008 Review of the NOPSA operational activities are generally consistent with these lessons.[205]

205 In particular, that review recommended, among other things, that (a) the regulations be made clear; (b) clearer guidelines should be prepared in consultation with stakeholders; (c) there should be a tripartite reference group that would, among other things, agree on improvement actions, have oversight of performance and disseminate information to stakeholders; (d) suitable accredited education modules should be established for employees; (e) there should be better KPIs that are related to the industry's risk profile and that are comparable with the industry's performance in other part of the world and with that of other industries.

Annex 26:
James Reason safety culture checklist

CHECKLIST FOR ASSESSING INSTITUTIONAL RESILIENCE

Scoring: YES = This is definitely the case in my organisation (scores 1); ? = "Don't know", "maybe" or "could be partially true" (scores 0.5); NO = This is definitely not the case in my organisation (scores zero).

	YES	?	NO
Mindful of danger: Top managers are ever mindful of the human and organisational factors that can endanger their operations.	☐	☐	☐
Accept setbacks: Top management accepts occasional setbacks and nasty surprises as inevitable. They anticipate that staff will make errors and train them to detect and recover from them.	☐	☐	☐
Committed: Top managers are genuinely committed to aviation safety and provide adequate resources to serve this end.	☐	☐	☐
Regular meetings: Safety-related issues are considered at high-level meetings on a regular basis, not just after some bad event.	☐	☐	☐
Events reviewed: Past events are thoroughly reviewed at top-level meetings and the lessons learned are implemented as global reforms rather than local repairs.	☐	☐	☐
Improved defence: After some mishap, the primary aim of top management is to identify the failed system defences and improve them, rather than to seek to divert responsibility to particular individuals.	☐	☐	☐
Health checks: Top management adopts a proactive stance towards safety. That is, it does some or all of the following: takes steps to identify recurrent error traps and remove them; strives to eliminate the workplace and organisational factors likely to provoke errors; "brainstorms" new scenarios of failure; and conducts regular "health checks" on the organisational processes known to contribute to mishaps.	☐	☐	☐
Institutional factors recognised: Top management recognises that error-provoking institutional factors (like under-manning, inadequate equipment, inexperience, patchy training, bad human-machine interfaces, etc.) are easier to manage and correct than fleeting psychological states such as distraction, inattention and forgetfulness.	☐	☐	☐
Data: It is understood that the effective management of safety, just like any other management process, depends critically on the collection, analysis and dissemination of relevant information.	☐	☐	☐
Vital signs: Management recognises the necessity of combining reactive outcome data (ie, the near miss and incident reporting system) with active process information. The latter entails far more than occasional audits. It involves the regular sampling of a variety of institutional parameters (scheduling, budgeting, fostering, procedures, defences, training, and the like), identifying which of these "vital signs" are most in need of attention, and then carrying out remedial actions.	☐	☐	☐
Staff attend safety meetings: Meetings relating to safety are attended by staff from a wide variety of departments and levels.	☐	☐	☐
Career boost: Assignment to a safety-related function (quality or risk management) is seen as a fast-track appointment, not a dead end. Such functions are accorded appropriate status and salary.	☐	☐	☐

	YES	?	NO
Money vs Safety: It is appreciated that commercial goals and safety issues can come into conflict. Measures are in place to recognise and resolve such conflicts in an effective and transparent manner.	☐	☐	☐
Reporting encouraged: Policies are in place to encourage everyone to raise safety-related issues (One of the defining characteristics of a pathological culture is that messengers are "shot" and whistleblowers dismissed or discredited).	☐	☐	☐
Trust: The organization recognises the critical dependence of a safety management system on the trust of the workforce – particularly in regard to reporting systems. A safe culture – that is, an informed culture – is the product of a reporting culture that, in turn, can only arise from a just culture.	☐	☐	☐
Qualified indemnity: Policies relating to near miss and incident reporting systems make clear the organisation's stance regarding qualified indemnity against sanctions, confidentiality, and the organisational separation of the data-collecting department from those involved in disciplinary proceedings.	☐	☐	☐
Blame: Disciplinary policies are based on an agreed (ie, negotiated) distinction between acceptable and unacceptable behaviour. It is recognised by all staff that a small proportion of unsafe acts are indeed reckless and warrant sanctions, but that the large majority of such acts should not attract punishment. The key determinant of blameworthiness is not so much the act itself – error or violation – as the nature of the behaviour in which it was embedded. Did this behaviour involve deliberate unwarranted risk-taking, or a course of action likely to produce avoidable errors? If so, then the act would be culpable regardless of whether it was an error or a violation.	☐	☐	☐
Non-technical skills: Line management encourages their staff to acquire the mental (or non-technical) as well as the technical skills necessary to achieve safe and effective performance. Mental skills include anticipating possible errors and rehearsing the appropriate recoveries. Such mental preparation at both the individual and organisational level is one of the hallmarks of high-reliability systems, and goes beyond routine simulator checks.	☐	☐	☐
Feedback: The organisation has in place rapid, useful and intelligible feedback channels to communicate the lessons learned from both the reactive and proactive safety information systems. Throughout, the emphasis is upon generalising these lessons to the system at large.	☐	☐	☐
Acknowledge error: The organisation has the will and the resources to acknowledge its errors, to apologise for them, and to reassure the victims (or their relatives) that the lessons learned from such accidents will help to prevent their recurrence.	☐	☐	☐

INTERPRETING YOUR SCORE

16-20 So healthy as to be barely credible.

11-15 You're in good shape, but don't forget to be uneasy.

6-10 Not at all bad but there's still a long way to go.

1-5 You are very vulnerable.

0 Jurassic Park

HEALTH WARNING

High scores on this checklist provide no guarantee of immunity from accidents or incidents.

Even the "healthiest" institutions can still have bad events. But a moderate to good score (8-15) suggests that you are striving hard to achieve a high degree of robustness while still meeting your other organisational objectives. The price of safety is chronic unease: complacency is the worst enemy.

There are no final victories in the struggle for safety.

Checklist written by Professor James Reason and presented at the 2000 Manly Conference.

Annex 27: Biographies of inspectors and investigation team members

Inspectors

Mr David Agostini

David Agostini is a consultant in the Oil and Gas sector having worked in the industry since 1957. He worked for Texaco as a petroleum engineer and production specialist, and later joined Woodside in a similar capacity. He subsequently managed drilling operations and offshore production. On secondment to Shell in the Hague he worked as deputy strategy manager for downstream oil and gas. Mr Agostini managed Woodside's LNG business, and was involved in marketing gas into Asia.

Mr Agostini is currently a non executive director of Neptune Marine, Chairman of the Western Australian Energy Research Alliance, and Chairman of the Australian Resources Research Centre (ARRC) advisory group. He chaired the state government Electricity Industry Reference Group (EIRG) and was a member of the COAG Energy Markets Review Panel. He holds engineering qualifications from the North Carolina State University, and is an Adjunct Professor in Oil & Gas Engineering at the University of Western Australia.

Mr Kym Bills

Kym Bills is Executive Director of the Australian Transport Safety Bureau, and has held that position since 1 July 1999 when the ATSB was established.

Mr Bills was head of the Commonwealth Maritime Division from 1994 when he was on the Board of ANL Limited and the Australian Maritime Safety Authority and chaired the Commonwealth/State

Marine and Ports Group. In 2005 he worked with the Rt Hon Sir John Wheeler reviewing Australia's airport security and policing.

Mr Bills's initial degrees were a B.A (Hons I) from the University of Adelaide and a M.Sc from the University of Oxford. He holds professional fellowships with the Chartered Institute of Logistics and Transport, the Safety Institute of Australia, the Australian Institute of Management, and the Australian Institute of Company Directors.

Research team
Consultants

Mr Bruce Gemmell

Bruce Gemmell is working as an independent consultant having retired in 2007 after 34 years in the Commonwealth public sector. Prior to retirement Mr Gemmell was Deputy Chief Executive Officer and Chief Operating Officer in the Civil Aviation Safety Authority (CASA) for six years from 2001 and had a lead role in oversighting and regulating Australia's aviation safety activities.

Prior to joining CASA Mr Gemmell worked in senior policy roles in aviation, rail, road transport, urban development and housing in a variety of Commonwealth government departments and was a Commissioner of Australian National Railways. Mr Gemmell was an inaugural member of the (then) Civil Aviation Authority and worked in the finance, air traffic services and project management areas of the Authority until 1991. He previously worked for about three years in the Department of Aviation and 11 years in the Department of Finance and the Treasury.

Mr Gemmell holds a degree in Economics from the University of Sydney and is a Fellow of the Australian Institute of Company Directors.

Professor Rolf Gubner

Professor Rolf Gubner is an expert in, amongst other things, microbiologically influenced corrosion, marine corrosion and corrosion protection. He is currently Chair of Corrosion at Curtin University of Technology in Western Australia, a position which is jointly funded by Woodside and Chevron Australia, and leads the Western Australian Corrosion Research Group (WACRG) located in the Curtin University of Technology Department of Applied Chemistry. He is also Vice-President of the European Federation of Corrosion and chairs its Working Party on Microbial Corrosion.

Prior to joining Curtin University, Professor Gubner Ph.D. was the Department Manager of the Swedish Corrosion and Metals Research Institute SwereaKIMAB AB for four years. His projects included microbiologically influenced corrosion of sea water injection in oil & gas wells, organic coatings in the marine and off-shore industry, localized corrosion initiation of stainless steels and electrochemical properties of intermetallic inclusions in duplex stainless steels, aluminum and magnesium alloys. He was also a Research Scientist at the Swedish Corrosion Institute where he was responsible for the localised scanning techniques laboratory. Prior to this he was in the UK as a Research Fellow at the University of Portsmouth where he investigated corrosion of steel surfaces in marine environments using state-of-the-art techniques of surface science.

Professor Andrew Hopkins

Professor Andrew Hopkins is Professor of Sociology at the Australian National University in Canberra. His research focuses on the organisational and cultural causes of major accidents. Professor Hopkins has been involved in various government OHS reviews and has done consultancy work for major companies in the resources sector. He speaks regularly to audiences around the world about the causes of major accidents.

Professor Hopkins was an expert witness at the Royal Commission into the causes of the fire at Esso's gas plant at Longford in Victoria in 1998. In 2001 he was the expert member of the Board of Inquiry into the exposure of Air Force maintenance workers to toxic chemicals.

Professor Hopkins was a consultant to the US Chemical Safety Board in their investigation of the Texas City accident. His book on that accident, *Failure to Learn: the BP Texas City Refinery Disaster,* was published in October 2008.

Professor Hopkins has a BSc and a MA from the Australian National University, a PhD from the University of Connecticut and is a Fellow of the Safety Institute of Australia. He is the winner of the 2008 European Process Safety Centre safety award.

Mr David Lesslie

David Lesslie is a Consultant specialising in providing advisory services in upstream oil and gas and Health, Safety and Environment (HSE) management. He is an experienced oil and gas executive with more than twenty-five years professional background in corporate, managerial, technical and consulting roles. He has held various positions with Woodside Energy Ltd from 1981–2006. He has significant experience in upstream oil and gas developments, including LNG, and has worked as an operational manager of two offshore facilities in Australia.

Mr Lesslie has a Master of Engineering Science and a Bachelor of Mechanical Engineering (Honours) from the University of Melbourne.

Mr Robin Stewart-Crompton

Robin Stewart-Crompton has been a consultant on OHS and industrial relations policies, law and practice since 2005. He recently chaired the National Review into Model OHS Laws.

Mr Stewart-Crompton was a Commonwealth public servant from 1975 to 2005, holding a position of Deputy Secretary of the Department of Employment and Workplace Relations from 1995 to 2000. He was member of the National OHS Commission from 1996 to 2004 and the Commission's CEO from 2000 to 2004. He has represented Australia at numerous international meetings and conferences.

Mr Stewart-Crompton's tertiary qualifications are an LL.B (Adelaide), a Graduate Diploma in International Law (ANU) and an LL.M (ANU). He was admitted as a legal practitioner in South Australia in 1972.

Public Servants

Dr Richard Batt

Richard Batt is a Senior Transport Safety Investigator with the Australian Transport Safety Bureau, specialising in human factors at both the individual and organisational level. He joined the Bureau in 1998. Dr Batt has a particular interest in the organisational aspects of safety and has been involved in a number of ATSB investigations in that area, including investigations into Sydney terminal area airspace, Australian Class G airspace, Ansett Australia maintenance safety deficiencies and the ICAO system for the control of continuing airworthiness, and organisational aspects related to the safety of helicopter emergency medical service operations.

Dr Batt has a BSc in psychology from Flinders University, South Australia, a PhD in aeronautical decision making from the University of Otago, New Zealand, and a Diploma of Transport Safety Investigation. Prior to joining the ATSB, Dr Batt worked in research in cognitive psychophysiology at the University of Adelaide. His main areas of study and research have been in human information processing, individual differences, and aeronautical decision making.

Ms Dianne Bravo

Dianne Bravo is a research officer on secondment from the Department of Resources, Energy and Tourism, Energy and Environment Division. Most recently, Ms Bravo has been involved in technology policy issues for renewable and clean energy including assisting with the development of a geothermal framework and roadmap and development of an international partnership. She has also managed the division's Senate Estimates hearing process for a range of energy matters including offshore petroleum issues on Varanus Island. Ms Bravo holds a BB (International Business & Economics) and an advanced certificate in accounting.

Ms Joanna Bunting

Joanna Bunting is an Assistant Manager on secondment from the Energy Security Branch of the Commonwealth Department of Resources, Energy and Tourism. In the Energy Security Branch, Ms Bunting specialises in domestic energy security issues such as security of supply and critical infrastructure protection. Her role includes significant liaison with the upstream and downstream energy industries through various Government-Industry fora including the Energy Infrastructure Assurance Advisory Group and the International Electricity Infrastructure Assurance Forum. Ms Bunting has a BSc and BA (Hons) from the University of Melbourne (2005) and a Diploma of International Relations from l'Institut d'Etudes Politiques (Sciences-Po) in Paris (2004).

Mr Vince D'Angelo

Mr D'Angelo headed the Western Australian Secretariat for the investigation. He is within the Department of Mines and Petroleum (DMP), Royalties Division as the Manager for Systems and Analysis. In this role he has extensive experience in analysing complex issues, handling negotiations and liaison at a high level between the mining industry and government. His past roles within DMP also include policy formulation, problem solving and establishing effective management systems and tools within an IT environment. Mr D'Angelo has a Bachelor of Business degree and has attained the level of Certified Public Accountant within the Australian Society of Accountants since 1995. He has recently completed an Advanced Management Program.

Ms Juliet Lautenbach

Juliet Lautenbach is a Manager on secondment from the Department of Resources Energy and Tourism, Resources Division. Ms Lautenbach has worked in industry and defence policy over a period of 13 years in the Commonwealth Public Service. During three years in the Resources Division, she has worked on offshore regulation, including a major project to consolidate regulations under the PSLA, and onshore minerals industry development. Ms Lautenbach has a BA (Hons) and a Master of Management (Industry Strategy) from the ANU.

Mr Michael Watson

Michael Watson is a Senior Transport Safety Investigator in the Australian Transport Safety Bureau's Aviation Branch. He has been involved in major ATSB systemic investigations, including the investigation into Mobil's AVGAS fuel contamination in 1999 and the investigation into Boeing 767 maintenance safety deficiencies at Ansett Australia in 2002. Mr Watson has a BSc in Safety and Health from Aston University in the UK, and a Master of Public Administration from the Australian National University and has held an Air Transport Pilot Licence from 1991. In the early 1990s, Mr Watson worked as a safety officer for a part of British Gas.

Ms Lee Furner

Lee Furner provided executive and administrative support.

Mr David Hope

David Hope provided desktop publishing services.

Annex 28: Visits and meetings held

Scheduled meetings

The Inspectors met with the following at least once, with multiple meetings with key regulators and stakeholders:

Ministers

Commonwealth

- Minister for Resources & Energy, Minister for Tourism
  The Hon Martin Ferguson AM MP and senior staff

State/Territory

- WA Minister for Mines & Petroleum, The Hon Norman Moore MLC and senior staff

Government bodies

State

- WA Department of Mines and Petroleum;
  - Executive Director, Geological Survey Division, Mr Tim Griffin
  - Director Petroleum & Environment Mr Bill Tinapple and Ms Beverley Bower
  - Business Division, Petroleum Branch, Principal Legislation & Policy Officer Mr Colin Harvey
  - Manager, Petroleum Pipelines, Petroleum & Major Hazard Facilities Safety Branch Mr Khalil Ihdaghid
  - Deputy Director-General, Strategic Policy Mr Stedman Ellis
  - General Manager Marine Safety Mr David Harrod
  - Petroleum & Environment Division, Petroleum Operations Engineer, Mr Neil Tyers
- Primary Industries & Resources SA, Chief Engineer, Petroleum and Geothermal Group Mr Michael Malavazos and colleagues

- Victorian Department of Primary Industries, Manager, Petroleum & Geothermal Operations Mr Terry McKinley and former Director Mr Phil Roberts
- Energy Safe Victoria, Director of Energy Safety, CEO Mr Ken Gardner and Mr Mike Ebdon
- Worksafe Victoria, Director, Hazard Management Division Mr Trevor Martin, Rod Gunn, Geoff Cooke, Mike Connell and Sean Byrne.

Commonwealth

- National Offshore Petroleum Safety Authority, CEO Mr John Clegg and Perth headquarters staff
- National Offshore Petroleum Safety Authority, Victorian team leader, Wayne Vernon
- National Offshore Petroleum Safety Authority Board of Directors
- Chairman, National Offshore Petroleum Safety Authority Board Mr William F Bloking
- National Offshore Petroleum Safety Authority Board Member Mr Rob King
- National Offshore Petroleum Safety Authority, former NOPSA Board Member (2004-2008) Mr Barry Adams
- Australian Maritime Safety Authority at Fremantle Office, CEO Mr Graham Peachey and colleagues
- Department of Resources, Energy & Tourism, A/g Head of Resources Division Mr Bob Pegler, A/g General Manager Offshore Resources Branch Mr Peter Livingston and staff
- Department of Resources, Energy & Tourism, Manager Safety Security and Environment Ms Kristina Anastasi and colleagues
- Productivity Commission, Commissioner Mr Philip Weickhardt and Mr Peter Garrick

Industry and associations

- Exxonmobil, Manager, Safety, Health, Environment & Security Mr Ron H Reiten
- Santos Ltd, Adelaide, Manager EHS, Sustainability & Indigenous Affairs Technical Mr Andrew Anthony and colleagues
- Australian Pipeline Industry Association, Chief Executive Ms Cheryl Cartwright and Mr Craig Bonar
- Woodside Energy Ltd, Executive Vice President, Health and Safety Dr Agu Kanstler

- Woodside Energy Ltd, Executive Vice President Production Mr Vince Santostafano
- Vermilion Oil & Gas Australia Pty Ltd, Managing Director Mr Bruce Lake
- Chevron Australia, WA Oil Asset Corrosion & Materials Specialist Mr Matthew Shield
- Australian Petroleum Production & Exploration Association, Director Skills & Safety Ms Miranda Taylor
- ConnocoPhilips, Darwin, HSE Manager, Mr Wesley Heinold (by telephone)
- Ionik Consulting, Mr Mark Linton and staff
- Mr Anthony Pooley, Executive Consultant Parsons Brinckerhoff
- Mr Brendan Hammond, Managing Director Seymour Associates
- Vanguard Solutions Pty Ltd, Managing Director Mr Brendan Fitzgerald
- Eni Australia, Development Project Manager, Blacktip project Mr Paolo Guaita, HSE Manager Sue Capper and colleague

International meetings

- US National Association of Corrosion Engineers, Director, Public Affairs Mr Cliff Johnson
- UK Health & Safety Executive, Head, Offshore Division, Mr Ian Whewell
- US Department of Transportation, Pipeline & Hazardous Materials Safety Administration, Associate Administrator, Office of Pipeline Safety Mr Jeffrey D Wiese and Mr Byron Coy
- US National Transportation Safety Board, Director, Office of Railroad, Pipeline & Hazardous Materials Investigations Mr Robert J. Chipkevich
- US Department of the Interior, Minerals Management Service, Chief, Offshore Regulatory Programs Mr Elmer P (Bud) Danenberger III
- Netherlands State Supervision of Mines, Inspector General of Mines Mr Jan de Jong
- Netherlands Shell Gas & Power, HSSE + Sustainable Development Manager Mr Alistair Hope, Mr René P.G.A. de Nier, Mr Rob Klein Nagelvoort and colleagues
- UK OGP International Associations of Oil & Gas Producers, Executive Director Mr Charles Bowen
- UK International Marine Contractors Association, Chief Executive Mr Hugh Williams and Ms Jane Bugler

- Norway Petroleum Safety Authority, Special Adviser Mr Odd Bjerre Finnestad and Mr Thor Gunner Dahl
- UK Hockway Cathodic Protection Systems, Chief Executive Officer Mr Alistair Ketner
- UK RSK Group PLC, Technical Director Mr David A Willis
- USA The Equity Engineering Group Inc, President-Principal Engineer Mr David A Osage, P.E.
- Netherlands Gasunie, Mr Roy van Elteren
- UK National Grid, Integrity Manager Mr Brian Woodhouse
- UK Interconnector (UK) Ltd, Mr Roy Crowther

Industry technical conferences and seminars

- 2009 Integrity Management Summit, Houston USA 11 February 2009
- 3rd annual Oil & Gas Pipeline Integrity Conference, Amsterdam, the Netherlands 16–18 February 2009
- International Standards Workshop for Australian Oil and Gas Industry, Perth 19–20 February 2009

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