FINAL

A CLOSEOUT EVALUATION OF THE KUMANG CLUSTER PHASE 1 (KUCL1) PROJECT

Prepared for
PETRONAS

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PREFACE

This IPA report summarises PETRONAS' Kumang Cluster Phase 1 (KUCL1) Project performance. This closeout evaluation of the KUCL1 Project compares the project's actual performance with the performance planned at authorisation. A comparison is also made with other similar, completed projects in Industry and with PETRONAS' recent performance. Based on this analysis, past IPA research, and project team input, lessons learned are provided that can be used to improve future project performance. This closeout evaluation was conducted 3 years after the KUCL1 Project achieved first gas in October 2011. As such, few original team members involved in execution were available for interviews.

IPA's prospective evaluation[1] interview was conducted in September 2008 when the KUCL1 Development Project had completed detailed design and procured long-lead items. This "late prospective" evaluation was intended to assist the project team in assessing the project status at authorisation and, most importantly, identifying areas needing immediate attention for the remaining execution scope. Since this evaluation, IPA's cost and schedule models were updated. In addition to including more recent projects and ongoing model refinement, some of IPA's recent models (namely the processing platform, well head platform and pipeline models) now include a regional (Asian or Malaysian) benchmark. Where applicable, this closeout evaluation has re-run the benchmarks for the project targets at authorisation to aid in comparisons with actual outcomes. *Please refer to the prospective report for the KUCL1 Project's original benchmarks and project drivers as they will not be repeated in this report.* Finally, the benchmarks presented in this report will be used to characterise the KUCL1 Project's performance in PETRONAS' Upstream Industry Benchmarking Consortium (UIBC)[2] metrics.

To supply industry benchmarks, we used IPA's Upstream Project Evaluation System (PES®).[3] The Upstream PES Database contains information on more than 1,400 projects conducted by more than 40 companies over the past 25 years. We measured the project's performance in the following areas: *Project Drivers*, *Project Execution Discipline*, and *Project Outcomes.*

Project team members supplied the information for this analysis in meetings held 15, 16, and 17 October 2014 in the KLCC Tower 1 project offices, Kuala Lumpur, Malaysia. Project team members present at these meetings included Noor Ramli Bin Othman, Rahmah Idius, M. Nadzin Hashim, Sulistianto Sunaryo, Farzahan Samsunnaha, M. Farid A. Rahman, Azlan Abdullah, Roslan B. Mat Nordin, M. Hood B. M. Lee, Wan Muzaffar B. Wan Mamat, M. Fauzi B. Mamat, Omar Zohrie M. Ali, M. Adib Ali Din, Muhamad Zazimi B. Asmawi, Johan Khalil Mas'od, Amizal Abu Bakar, Noraishah M. Razali' Kamilah Bt Muhdabd Jamil, Ahmad Zahid Murshidi B. Zawair, Mohd Zarir B. Musa, Tore Zahl-Johansen, Firdawos Ahmad Fauzi, Fadli Adlan B. Muslim and Nurul Huda Abd Karim (SKO).

Jop van Hattum and Cameron Ashcroft represented IPA. Although project team members provided information, the interpretation and analysis are IPA's and do not necessarily reflect the views of those interviewed. For more information or for answers to questions, contact Jop van Hattum of IPA Australia at +61 3 9458 7300 or jvanhattum@IPAGlobal.com.

[1] Trung Ghi, *A Prospective Evaluation of the Kumang Cluster Phase 1 Development Project*, IPA, PET-8005-PRO, December 2008.
[2] The UIBC is a voluntary association of owner firms in the upstream industry that have employed IPA's quantitative benchmarking approach. The members exchange data, information, and metrics to improve the effectiveness of their project systems.
[3] PES is a registered trademark of IPA.

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KEY MESSAGE

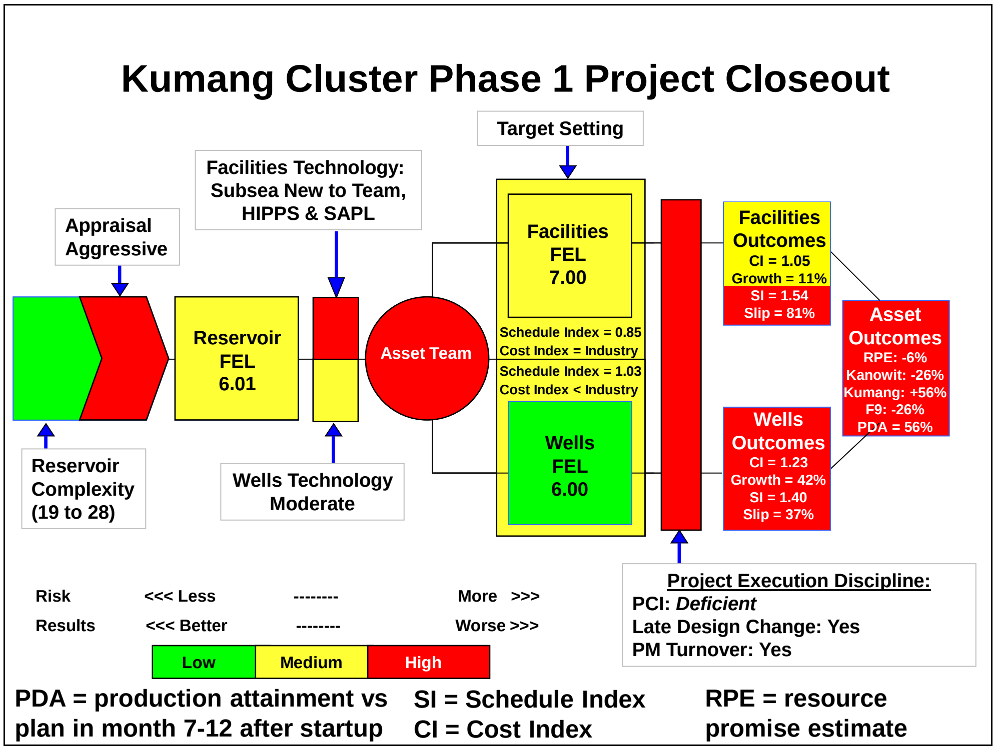


Figure 1

The Kumang Cluster Phase 1 (KUCL1) Project was a billion-dollar venture to augment gas supply for Malaysian LNG-2 (MLNG2) at Bintulu, Sarawak. At sanction, the KUCL1 megaproject[4] was schedule-driven but lacked key fundamental megaproject Best Practices. Instead, the project had weak and incomplete basic data (lacking clear objectives, stakeholder alignment, and subsurface data), an *Aggressive* reservoir appraisal, less than *Best Practical* project definition with significant gaps (despite completing detailed design for pipelines and platforms) such as the absence of a Project Execution Plan and Project Controls systems and resources, and *Undeveloped* Team Development.

Failing to recognise the project's complexity, Petronas decided to change the concept for Kanowit to a subsea development to obtain in-house capability to perform subsea projects. It is unclear why this project was chosen to obtain such expertise rather than perform a subsea project on a reservoir from which more information was available and which could be done in isolation, free from schedule pressure and megaproject complexities.

Consequently, the project had mixed cost competitiveness results but eroded value due to cost growth and severe schedule slip in subsea and drilling. Resource promise results were mixed with reserves increasing on Kumang but decreasing in Kanowit and F9 whilst a downside scenario has been locked in due to the Kumang field's pipeline and well capacity limitation of 148 MMscfd.[5] Production attainment, measured by IPA,[6] has been poor due to a variety of factors including reservoir performance (in particular early onset of water production on F9), incorrect reservoir data (particularly higher reservoir temperature causing operability

[4] IPA defines megaprojects as those with a capital expenditure that exceeds US$1 billion. Other factors specific to megaprojects include numerous and complex stakeholders, expensive and difficult to obtain basic data, multiple and distinct scope elements, and a venture with a large number of scope elements.
[5] MMscfd = million standard cubic feet per day
[6] IPA measures production attainment as actual production in months 7 through 12 after startup. KUCL1 Kumang started up 10.5 months after first gas from F9, and Kanowit started up 16 months after first gas.

issues due to incorrect design on Kanowit), schedule delays, commissioning issues, and lower than expected gas demand.

This KUCL1 Project closeout assessment reveals an issue common to megaprojects: failing to address fundamental shaping issues that encompass basic data, stakeholder alignment, and clarity of objectives for project success. The KUCL1 Project had an *Aggressive* appraisal strategy, employed poor planning and controls practices, lacked team integration and adequate resourcing. In addition, the project applied technology that was new to the company for which the challenges were exacerbated by changing company requirements which required technology that was new to industry to be implemented during execution. This report correlates the practices employed on the KUCL1 Project with the outcomes as measured with IPA's proprietary Project Evaluation System (PES).[7]

[7] PES is a registered trademark of IPA.

PROJECT OVERVIEW

SUMMARY

The KUCL1 Gas Development Project was sanctioned in September 2008 for a total investment of RM6.0 billion and a target first gas date of 14 October 2010. Prior to full funds authorisation, a pre-funding allowance was granted in February 2008 for the sum of RM595 million to progress detailed design which had commenced in October 2007 and to procure certain long-lead items.

The project's objective was to develop the F9, Kumang, and Kanowit gas fields with a total gas and condensate reserve of 309 MMBOE[8] from 11 wells. First gas was planned to flow from F9 with Kumang and Kanowit to follow until project completion, planned on 12 December 2010.

The project achieved first gas on 31 August 2011 from F9, 10.5 months later than planned. The Kumang field came online 6 May 2012, and the Kanowit field started production 23 December 2012. However, the Kanowit subsea system experienced several subsea leaks and was required to shut down because of higher than expected reservoir temperatures that the subsea system had not been designed to handle. The project was therefore not completed when it was handed over to operations on 30 June 2013.

The project's forecast final cost is RM6.9 billion, however project accounts are expected to be closed at the end of December 2014, which is after this analysis' completion.

The project's total man hours was just in excess of 14 million, in which four lost time injuries (LTIs) and 25 recordable injuries were recorded.

Post start-up reserves estimates indicated reserves downgrades on F9 and Kanowit but a reserve increase on Kumang, resulting in a net loss in reserves of 6 percent to 284 MMBOE. Reservoir performance on F9 was most disappointing with the early onset of water production. In order to make up for production shortfalls, a further two infill wells are planned to be drilled in 2015.

PROJECT BACKGROUND

Kumang Cluster fields are located approximately 200 km offshore Bintulu, Sarawak, with water depths ranging from 59 m to 102 m in sub-blocks SK 308, 313, and 315. Kumang Cluster gas fields, at the time of project sanction consisted of ten (10) gas reservoirs: Kanowit, F9, Kumang, F22, F12, F27, F11, A3, Selar Marine, and Bunga Pelaga. These reservoirs were planned to be developed in two phases. Phase 1 development consists of Kanowit, F9, and Kumang fields East section only (the West section was planned for Phase 2). The total resource promise for all reservoirs was about 2.7 trillion cubic feet (Tcf) of gas, to be recovered by 23 development wells. Current plans for further development are limited to infill drilling on F9 only with other prospects failing to meet economic hurdle rates due to lower reserves expectations. Since then six more fields have been added with an estimated ultimate recovery of 6.6 Tcf. Further development is planned as follows:

- Phase 2a: F9 south, F12, Anjung, Anjung south
- Phase 2b: F22, NC4, NC10, F2 Attic (subject to further review)
- Phase 3: F27, A3 Selar Marine

[8] MMBOE = Million barrel of oil equivalent

Petronas Carigali Sdn Bhd (PCSB[9]) operates the fields under an existing production-sharing contract (PSC) with PETRONAS. Kumang Cluster fields are 100 percent PCSB equity.In September 2005, the Kumang Cluster development PSC was signed and will expire in 2025. PETRONAS provided PCSB an opportunity to develop these fields to ensure supply security to the MLNG2 plant in Bintulu in anticipation of a gas shortfall by 2010. KUCL1 was developed to meet the PSC requirement of 350 MMscfd for the first year and 500 MMscfd for subsequent years.

PROJECT SCOPE AND TECHNOLOGY

The KUCL1 Project developed the Kanowit, F9, and Kumang fields to be followed by other fields at a later stage. Kanowit was selected as the hub for the Kumang Cluster Development Project where a central processing platform was built (KAKG-A) capable of processing 550 MMscfd of gas and 24,000 barrels of condensate per day bridge linked to a venting platform (KAV-A).

The three fields were developed as follows:

- Kanowit was developed with two subsea wells, each capable of 150 MMscfd of gas production in 77 m water depth, connected to a 24-inch x 5 km infield flowline with 200 MMscfd capacity

- Kumang was developed with a 9-slot well head platform (KUJT-A) and 5 platform wells each capable of 30 MMscfd connected to an 18-inch x 21 km infield flowline with 148 MMscfd capacity

- F9 is developed with a 6-slot well head platform (F9JT-A) in 97 m water depth and 3 platform wells each capable of about 85 MMscfd connected to a 28-inch x 57 km infield flowline with 350 MMscfd capacity;

- The KAKG-A central processing platform is connected to the Malaysia Liquefied Natural Gas (MLNG) plant at Bintulu, Sarawak, via a 28-inch x 180 km export pipeline

Kumang Cluster Phase I Development was planned with a total of 11 development wells, but drilled ten wells instead (i.e., three, instead of four, wells on F9; five wells at Kumang; and two subsea wells for Kanowit. The Kanowit wells were drilled with a semi-submersible drill rig while the Kumang and F9 wells were drilled with a tender assisted drill rig. The Kanowit, Kumang, and F9 fields had an estimated recovery of 525 billion cubic feet (Bcf), 384 Bcf, and 663 Bcf of gas, respectively. Figure 2 below shows the field layout for the KUCL1 Project. The Petronas Floating Liquefied Natural Gas (PFLNG) facility will be installed in 2015 and is not part of the evaluated project scope.

[9] PETRONAS carries out exploration, development, and production activities in Malaysia through PSCs with a number of international oil and gas companies and with its wholly owned subsidiary, Petronas Carigali Sdn Bhd.

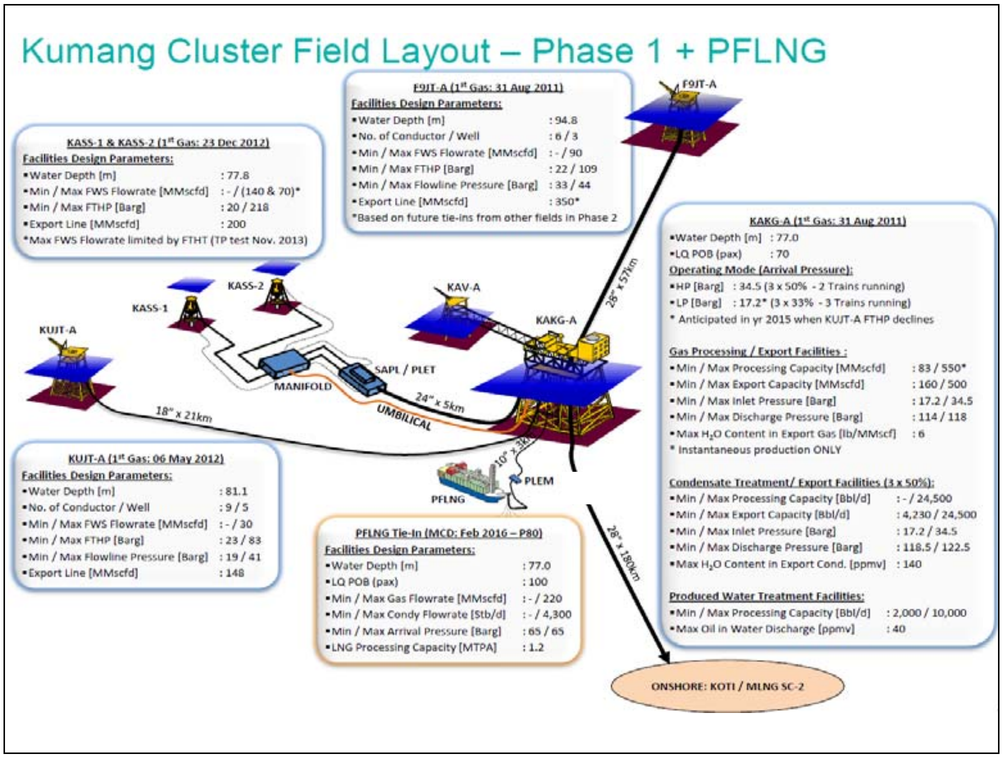


Figure 2

CONTRACTING STRATEGY

The project's contracting strategy had a number of objectives which were to:

- Use existing frame agreements where possible
- Bundle projects to reap rewards of synergies and secure yard slots
- Minimise any chance of cost overruns and changes on fabrication contracts
- Reduce the cost of transportation and installation (T&I)

The projects' contracting strategy was originally focussed around lump-sum engineering, procurement, construction, and commissioning (EPCC) for the fixed structures (F9JT-A, KUJT-A, and KAKG-A). However, in July 2007, near the end of FEED, the contracting strategy changed to lump-sum procurement, construction, and commissioning (PCC), because PCSB senior management wanted to pursue synergies between projects. Therefore, a few major projects with similar concepts and similar first gas date were bundled together; the fabrication yards were getting busy, and management could secure those yards by integrating several projects. This bundling strategy would therefore allow PCSB to directly negotiate (as opposed to competitive bidding) with the fabrication yard contractors.

From July 2007 onward, the team prepared the rollover contract for Perunding Ranhill Worley Sdn Bhd from FEED to detailed engineering. The PCC tender package was also prepared. PCSB formed a task force to coordinate the contracting packages under the bundling strategy. The team presented the final contracting package to management for approval in late 2007. However, management questioned why the team did not use the existing umbrella contract for commissioning. Therefore, the contracting strategy was rejected and changed to a procurement and construction (PC) lump-sum contract with commissioning done under the existing umbrella contracts with Kencana HL and Shapadu Engineering.

The team planned to install all components by October 2009 before the monsoon season, which would enable the project to achieve first gas by June 2010. However, the direct negotiation approach (which was expected to take less time) took longer than expected and, in fact, was longer than the expected time if competitive bidding had been used. The PC bundling package was presented to the Central Tender Committee (CTC) in August 2008 and was endorsed then.

The PC contracts were split into four packages and awarded as follows:

- Package A: Topsides KAKG-A awarded to Sime Darby
- Package B: Topsides KUJT-A & F9JT-A awarded to Sime Darby
- Package C: Jacket F9JT-A, KAV-A tripod, and bridge awarded to Oilfab Sdn Bhd
- Package D: Jackets KUJT-A and KAKG-A, awarded to Ramunia Fabricators Sdn Bhd

TL Offshore (TLO) transported and installed the structures in 2009 using the Sapura3000, and Enterprise 3 and Lewek Champion installed pipeline under a long-term PCSB barge contract.

Mitco Japan managed pipeline procurement under a master services agreement with Petronas. In 2010, PCSB changed to using the Pan-Malaysian Transportation and Installation Contract (PMTIC) to install the remaining scope, which included DB264, pipeline and riser installation, and DB101 and LTS3000 for KAK-G topsides installation.

The hook-up and commissioning (HUC) contract for KAKG-A and KAV-A was awarded to Kencana HL on 3 June 2010. The wellhead platforms' HUC contract was awarded to Shapadu Engineering on 1 September 2009.

At the start of detailed design Petronas decided to develop the Kanowit field with a subsea system primarily to develop in in-house capability to perform subsea projects, and which at the time and in the team's preliminary estimates delivered the lowest cost development option. Therefore an in-house FEED was performed for the subsea system.

Two EPC contract were awarded to Aker Process systems for subsea hardware and umbilicals for which Aker therefore performed the detailed design. The detailed design phase uncovered a number issues that were not adequately addressed during FEED which led to changes and delays. Subsea hardware including subsea trees, controls, manifold, jumpers, and pipeline end terminal (PLET) with high integrity pressure protection system (HIPPS) and subsea automated pig launcher (SAPL) was delivered by Aker Process Systems in Malaysia. The subsea umbilical was delivered by Aker Process Systems in Norway.

Subsea7 provided subsea installation and HUC of subsea systems with Nexus performing commissioning services.

The tender assisted drilling (TAD) and semi-submersible rigs were contracted and scheduled for the drilling program by the drilling function. The NAGA-1 semi-submersible rig rate was US$145,000 per day, which was lower than the estimated US$200,000 per day. The TAD rig was contracted for US$129,000 per day through an umbrella contract. However, the rig named Global Sapphire (and since has been renamed to Glenn Tanar) assigned to the project, was not the team's originally selected rig and did not meet the team's original specifications. This resulted in needed modifications to the wellhead platforms and the rig to accommodate the interfaces of the derrick with the wellhead platform structure. Moreover, the rig had severe problems while rigging up and, once operational, had severe problems with its topdrive and mudsystems which caused significant downtime; PCSB eventually managed to negotiate a lower rig rate of US$104,500 per day whilst refusing to pay for non-productive time (NPT).

Onshore tie-in works were provided under a PCC contract awarded 19 October 2009 to Petra Resources.

PROJECT HISTORY

The following summary history of the KUCL1 Project is provided to put the project's cost, schedule, and production attainment into context.

- A preliminary resource assessment carried out by PCSB using Petronas Management Unit (PMU[10]) data and available maps was presented and endorsed by PCSB Management on 15 April 2005. The total reserve for all ten fields was on the order of 2.7 trillion square cubic feet (Tcf) gas, to be recovered from 23 development wells and 9 reservoirs including: F9 north, Kumang, F11, F12, F22, F27, A3, Selar Marine and Bunga Pelaga.

- A Production Sharing Contract (PSC) was signed in September 2005. PETRONAS provided PCSB an opportunity to develop these fields to provide supply security to the MLNG plant in Bintulu in anticipation of gas shortfall by 2010. Kumang Cluster will be developed to meet the PSC requirement of 350 MMscfd for the first year and 500 MMscfd for following years.

- The project commenced 1 February 2006, and a concept engineering study was awarded to MMC Oil and Gas Sdn. Bhd. on 24 July 2006 and completed 22 December 2006.

- Milestone reviews 3 and 4 (MR3 & MR4) were held 22 March 2007 to endorse the development concept and economics which included wellhead platforms on Kumang, Kanowit, and F9 with the central processing platform located at F9.

- The original overall contracting strategy was presented to Petronas and approved 30 November 2006.

- Front-end engineering included route surveys, an environmental impact assessment, and soil borings which commenced in February 2007.

- Front-end engineering and design (FEED) commenced 30 May 2007 and was awarded to Perunding Ranhill Worley Sdn Bhd. This contract was extended to cover detailed design following the Petronas Integrated Strategy for Local Fabrication Yards. The EPCC contract strategy was amended to provide procurement and construction only with commissioning also under a separate contract. This FEED contract rolled over into detailed design on 27 October 2007. FEED, however, continued for the Kanowit subsea scope until mid-2008.

- Long lead item procurement commenced in January 2007 and included the gas turbine compressor, glycol dehydration system, pedestal crane, pressure vessels and fuel gas skids, plate heat exchanger, pumps, valves, gas turbine, micro-engine and diesel engine generators, metering packages, structural steel, and line pipe.

- The field development plan was approved 6 June 2007, but an addendum with amendments (such as the subsea development for Kanowit, relocation of the CPP and the revised contact strategy) to the proposed development was submitted to Petronas on 29 August 2008.

[10] PMU is the governing body for the Oil and Gas development in Malaysia.

- The project decided to change the Kanowit's development concept to a subsea development on 15 August 2007. This also changed the central processing platform's location to the Kanowit field.

- A Gas Sales Agreement was signed between Petronas and PCSB on 31 December 2007, and the project was granted advanced funding of RM595 million on 15 February 2008.

- The PC packages tender plan was approved on 16 October 2008; however, fabrication and construction for jackets and topsides had commenced as early as July 2008.

- Full funds authorization (Tier 2 Sanction) occurred on 25 September 2008.

- Contracting for the subsea hardware frame agreement took place between November 2007 and September 2008. However, the design and fabrication contract wasn't awarded to Aker Process Systems until 15 July 2009.

- The KAKG-A topsides installation, which had a total estimated weight of 17,000 metric tons (mt), could not be completed in one lift. Therefore, the main support frame's (MSF's) design needed to be changed into three components to accommodate installation with seven heavy lifts not exceeding 3,000 mt, the limit of the heavy lift vessel LTS3000. This caused total tonnage to increase to around 18,000 mt.

- Platform jackets (KAKG-A, F9JT-A, and KUJT-A) and topsides (F9JT-A and KUJT-A) were transported and installed from June 2009 until September 2009 prior to the monsoon. During this time pipelines were installed from MLNG to KAKG-A, KUJT-A to KAKG-A, and F9JT-A to KAKG-A.

- On 12th February 2010 seven additional reservoirs were annexed to the PSC namely: Kanowit, PC4, Anjung, Anjung South, NC4, NC10 and F2 Attic.

- During 2010, PCSB restructured its organization which also affected the KUCL1 project team. The organization changed from being heavily siloed to being more integrated, and many project management systems were implemented, such as the Petronas Project Management System (PPMS) and the project controls group. The project experienced significant team member turnover during this time. The project approved value was re-baselined in 2010 to RM6.9 billion which required compliance with the new processes.Only then was a project execution plan for the KUCL1 Project developed. Records before this time could not be retrieved due to the lack of a document control system.

- Between 2009 and 2010, the T&I contract was renegotiated and awarded to TL Offshore (TLO) under the PMTIC. Therefore, the remaining structures, pipelines, and risers were installed with vessels under TLO management.

- Platform drilling using a tender assisted derrick barge was planned to commence in September 2009. The drilling rig initially earmarked for the work was re-assigned to other projects by PCSB management. The Global Sapphire was assigned to KUCL1. However, the rig was late and did not arrive in field until May 2010 when it subsequently experienced rig-up difficulties, taking some 75 days. Rig and wellhead platform modifications were needed to accommodate the interfaces. Two wells were drilled on F9 with significant downtime due to topsides failure and failure of other rig systems causing a decision to move the Global Sapphire off location for refurbishment in dry dock. The rig was remobilized to the site on 26 January 2011 to complete the remaining F9 wells scope prior to moving to Kumang on 28 June 2011. Drilling on Kumang was completed 14 May 2012.

- Petra Engineering commenced HUC on 5 March 2010 but took longer than planned due to KAKG-A carry-over work from the fabrication yard and issues between commissioning and handover to operations for which criteria were not well defined. Also, the extended time between wellhead platform installation and KAKG-A jacket and commissioning caused weathering and misalignment issues.

- First gas was initially planned for 14 October 2010, but due to commissioning and drilling delays, this was not achieved until 31 August 2011 from F9 only. Kumang followed on 10 May 2012.

- Kanowit drilling occurred from 30 October 2011 until 12 April 2012 with the semi-submersible drill rig Naga-1 under long-term contract with PCSB.

- Subsea hardware items delivery took longer than planned due to required changes in design from FEED to detailed design. These changes gave an out to extend the delivery date to June 2012, more than two years behind schedule. Changes included addition of the SAPL on the PLET and HIPPS which substantially increased the PLET's weight. The 24-inch jumper from the manifold to the PLET could not be certified for the expected fluid properties which required a design to change to 2 x 12-inch jumpers. After consulting fishery representatives, protective cages were required to be to NORSOK standard and mattresses were needed to cover jumpers.

- The subsea installation contract was awarded to Subsea7. Their installation vessel was not available when the subsea hardware items were ready for delivery and, thus, did not commence installation until September 2012 and had to be completed prior to the monsoon in November 2012.

- Subsea commissioning was performed by Nexus, and first gas flowed from the field on 23 December 2012. However, due to higher reservoir temperatures, the field was required to be shut-in and following investigation could flow only one well. During an as-built survey, a hydrocarbon leak was found on the manifold, which also required the field to be shut-in. Further leaks of hydraulic fluid and methanol were repaired between March 2013 and September 2013.

- In March 2012, PCSB Board approved the relinquishment of two fields to Petronas which were F11 and Bunga Pelaga.

- The project was transferred to operations on 30 June 2013, although some commissioning and repair work was still ongoing.

BASIS OF COMPARISON

In this report, we use IPA's Upstream Database to compare the KUCL1 Project with a number of similar industry projects. The Upstream Database contains more than 1,400 recent projects. We used a set of recent projects to establish industry benchmarks for the KUCL1 Project drivers. Table 1 outlines the dataset's characteristics.

Table 1
Characteristics of Recent Subset of Upstream Projects

Characteristic	KUCL1 Project	Dataset (404 Projects)		
		Minimum	Median	Maximum
Year of Sanction	2008	2004	2007	2012
Country/Region	Malaysia/Asia	Asia 23 percent, North America 16 percent, Europe 19 percent, Africa 13 percent, South America 13 percent, Oceania 7 percent, Others 9 percent		
Actual Asset Cost (^{2003}US$ million)	1,090	<10	143	>3,000
Water Depth (m)	75 to 97	<20	150	>3,000
Facilities Concept (Dominant)	Fixed platform	Fixed platform 26 percent, Revamp 11 percent, Others 63 percent		

We also recognise the KUCL1 Projects' Megaproject characteristics. IPA draws specific Best Practices from its megaprojects' database. The characteristics of this database are shown in Table 2 below.

Table 2
Characteristics of Recent Subset of Mega Projects

Characteristic	KUCL1 Project	Dataset (318 Projects)		
		Minimum	Median	Maximum
Year of Sanction	2008	2004	2005	2012
Country/Region	Malaysia/Asia	Asia 9 percent, North America 20 percent, Europe 15 percent, Africa 9 percent, South America 19 percent, Oceania 9 percent, Middle East 15 percent, Central Asia 4 percent		
Actual Asset Cost (^{2003}US$ million)	1,090	1,000	3,200	>18,000
Duration (months)	68	<20	43	>70
Industry Sectors	Upstream	Upstream 40 percent, LNG 8 percent, Pipelines 2 percent, Power Generation 3 percent, Chemicals 10 percent, Minerals & Metals 15 percent, Refining 20 percent, Other 2 percent		

To benchmark the KUCL1 Project's estimated and actual cost and schedule, we used IPA models, including the Well Construction Model for the well construction program and the Offshore Time of Engineering and Construction (TEC) Model to benchmark the project's execution duration. The characteristics of the datasets used to develop these models are summarised in Table 3 to Table 8. The KUCL1 Project's characteristics lie within the range of our applicable model datasets and are therefore benchmarked.

Table 3
Characteristics of the Well Construction Component Model Dataset

Characteristic	KUCL1 Project	Dataset (78 projects)		
		Minimum	Median	Maximum
Year of Sanction	2008	1997	2004	2008
Total Actual Cost (^{2003}US$ million)	133	3	66	700
Average Water Depth (m)	77 - 97	12	475	>2,200
Country/Region	Malaysia/Asia	Asia 16 percent, North America 19 percent, South America 9 percent, Europe 33 percent, Africa 13 percent, Oceania 10 percent		
Program Duration (days)	266	12	240	>2,000

Table 4
Characteristics of the Subsea Model Dataset

Characteristic	KUCL1 Project	Dataset (361 projects)		
		Minimum	Median	Maximum
Year of Sanction	2008	1998	2004	2012
Country/Region	Malaysia/Asia	GoM[11] 21 percent, Europe 37 percent, Africa 10 percent, South America 14 percent, Oceania 9 percent, South East Asia 8 percent, Middle East 1 percent		
Water Depth (m)	77	20	390	>2,500
No. of Wells	2	1	5	>50
Flowline Length (km)	5	<0.5	26	>400

Table 5
Characteristics of the Wellhead Platform Model Dataset

Characteristic	KUCL1 Project	Dataset (350 projects)		
		Minimum	Median	Maximum
Year of Sanction	2008	1990	2004	2013
Country/Region	Malaysia/Asia	Asia 39 percent, GoM 15 percent, South America 6 percent, Other 14 percent, Europe 13 percent, Africa 13 percent		
Water Depth (m)	77 – 97	3	52	280
Topsides Dry Weight (mt)	1,760 and 1,640	132	800	>9,600

[11] GoM = Gulf of Mexico

Table 6
Characteristics of the Offshore Pipelines Model Dataset

Characteristic	KUCL1 Project	Dataset (350 projects)		
		Minimum	Median	Maximum
Year of Sanction	2008	1999	2001	2009
Country/Region	Malaysia/Asia	Asia 28 percent, North America 19 percent, Europe 15 percent, South America 15 percent, Africa 12 percent, Middle East 6 percent, Oceania 5 percent		
Water Depth (meters)	75 – 95	3	52	280
Pipeline Length (km)	5 – 180	0.1	45	>700
Diameter (inch)	18 – 28	4	17	50

Table 7
Characteristics of the Central Processing Platform Model Dataset

Characteristic	KUCL1 Project	Dataset (120 projects)		
		Minimum	Median	Maximum
Year of Sanction	2008	1990	2004	2013
Country/Region	Malaysia/Asia	Europe 19 percent, North America 18 percent, Africa 16 percent, South East Asia 26 percent, Other 21 percent		
Water Depth (meters)	77	3	32	>300
Throughput (MMscfd)	500	20	140	>1,100

Table 8
Characteristics of the Offshore Execution Duration Model Dataset

Characteristic	KUCL1 Project	Dataset (259 projects)		
		Minimum	Median	Maximum
Year of Sanction	2008	1989	2000	2008
Country/Region	Malaysia/Asia	Asia 15 percent, GoM 19 percent, Europe 35 percent, Africa 11 percent, South America 11 percent, Other 9 percent		
Total Actual Cost (^{2003}US$ million)	1,140	6	186	>4,500
Offshore Revamp (percent)	0	0	0	100
Installation Window (months)	8	4	12	12

PROJECT BENCHMARKS

PROJECT OUTCOMES

Table 9 summarises the KUCL1 Project's estimated and actual cost outcomes compared with Industry, PETRONAS, and top quartile benchmarks. Please refer to Table 17 in Appendix A for a breakdown of the estimated and actual cost associated with the Project.

Table 9
KUCL1 Project Cost Competitiveness Metrics Summary (Costs in RM millions MOD)

Outcome Metric	KUCL1 Project		Industry Average (index = 1.00)	PETRONAS Average[12]	Top Quartile
	Estimated at Sanction	Actual			
Weighted Average Facilities (index)	(0.93)	(1.03)	(1.00)	(1.08)	Not Applicable
Platforms (index):				As above	
- **KAKG-A including KAV-A**	2,559 (1.06)	2,576 (1.10)	2,351		1,938
- **KUJT-A**	338 (0.97)	353 (1.07)	331		291
- **F9JT-A**	338 (0.80)	371 (0.91)	409		360
Subsea (index): - **KASS**[13]	393 (1.07)	711[14] (1.97)	361	Not Available	319
Pipelines[15] **(index):**				(1.09)	
- **Kumang**	101 (0.57)	108 (0.59)	183		135
- **F9**	325 (0.54)	402 (0.65)	623		456
- **Export**	1,015 (0.91)	1,047 (0.90)	1,168		850
Well Construction Program (index)	712 (0.83)	1,014 (1.23)	825	(0.89)	Not Applicable
Well Construction:[16]				As above	
- **F9**	173 (0.70)	339 (1.39)	244		190
- **Kumang**	275 (0.68)	356 (0.89)	399		311
- **Kanowit**	264 (1.36)	319 (1.76)	182		142

The KUCL1 Project's cost competitiveness was around industry average in Malaysia for wellhead platforms and central processing platform. The subsea cost index was higher than Industry due to late changes and issues during execution but also includes items not normally in scope such as the HIPPS and SAPL. The pipelines cost index was better than Industry in Malaysia. Well construction cost was worse than planned and overall higher than the industry average due to significant challenges during execution.

[12] As reported at IPA's annual Upstream Industry Benchmarking Consortium (UIBC) meeting in November 2013 (UIBC 2013). The UIBC is a voluntary association of owner firms in the upstream industry that employ IPA's quantitative benchmarking approach. The members exchange data, information, and metrics to improve the effectiveness of their project systems.

[13] For this analysis, the 24-inch x 5 km pipeline from Kanowit to KAKG-A has been included in our subsea analysis, which is consistent with our approach during the prospective evaluation and typical subsea projects IPA evaluates. The estimated and actual costs of the Kanowit pipeline were RM75 and RM105 million, respectively, with the industry average for this pipeline predicted at RM134 million providing indexes of 0.51 and 0.78, respectively.

[14] The actual cost for comparison with the benchmark excludes the cost for HIPPS (RM31.7 million) and the cost of the Subsea Automated Pig Launcher (RM45.4 million)

[15] For this analysis, concrete coating has been removed from the project cost to provide a scope adjusted benchmark which is compared with pipeline projects in IPA's databases.

[16] The drilling campaign for each individual reservoir was benchmarked. This was considered more appropriate to reflect that two different drilling rigs were used with a tender-assisted drilling rig on Kumang and F9 and a semi-submersible drilling rig on Kanowit and that Kumang is a clastic reservoir whilst Kanowit and F9 are both carbonate reservoirs.

Table 10
KUCL1 Project Cost Deviation Metrics Summary

Outcome Metric	KUCL1 Project	Industry Average	PETRONAS Average[17]	Top Quartile
Asset	15 percent	7 percent	-13 percent	7 percent
Facilities	11 percent	5 percent	-21 percent	4 percent
Platforms: - **KAKG-A** - **KAV-A** - **KUJT-A** - **F9JT-A**	0 percent 30 percent 4 percent 10 percent	As above	As above	As above
Pipelines: - **Kumang** - **F9** - **Kanowit** - **Export**	29 percent 20 percent 39 percent 2 percent	As above	As above	As above
Subsea: - **KASS (w/o Kanowit Pipeline)**	116 percent	As above	As above	As above
Onshore tie-in	25 percent	Not Available	Not Available	Not Available
Overall Well Construction Program	42 percent	6 percent	-9 percent	1 percent
Well Construction Program - **F9** - **Kumang** - **Kanowit**	96 percent 29 percent 21 percent	As above	As above	As above

As shown in Table 10, the KUCL1 Project had an overall project cost growth of 15 percent, with 11 percent in facilities and 42 percent in well construction. Notably, the central processing platform and export pipeline, which could be considered the most challenging project components, came in on budget. This was offset by very poor cost predictability for subsea, which experienced 116 percent cost growth, and the F9 drilling program, which experienced 96 percent cost growth. Other project components experienced between 20 and 30 percent cost growth disregarding some outliers.

Table 11
KUCL1 Project Schedule Outcome Metrics Summary

Outcome Metric	KUCL1 Project		Industry Average	PETRONAS Average[18]	Top Quartile
	Planned at Sanction	Actual			
Schedule Effectiveness					
Facilities Execution in Months (Index)	38 months (0.85)	68 months (1.54)	44 months	(1.02)	(0.99)
Well Construction in Days (Index) - **F9** - **Kumang** - **Kanowit**	450 days (1.03) 140 days (1.08) 201 days (0.93) 110 days (1.20)	615 days (1.40) 201 days (1.55) 255 days (1.18) 159 days (1.73)	438 days 130 days 216 days 92 days	(0.65)	(0.93)
Schedule Deviation					
Facilities Execution	Not applicable	81 percent	10 percent	3 percent	5 percent
Well Construction	Not applicable	37 percent	Not available		

[17] As reported at IPA's UIBC 2013.
[18] As reported at UIBC 2013.

Please refer to Table 18 in the appendix for a full account of the project's planned and actual schedule.

As shown in Table 11, the KUCL1 Project's actual execution duration of 68 months was longer than the planned duration of 38 months and the industry average performance of 44 months. At project completion on 30 June 2013, the KUCL1 Project's execution was 54 percent slower than Industry. The KUCL1 Project's well construction duration was 40 percent slower than Industry and 37 percent slower than planned.

Safety

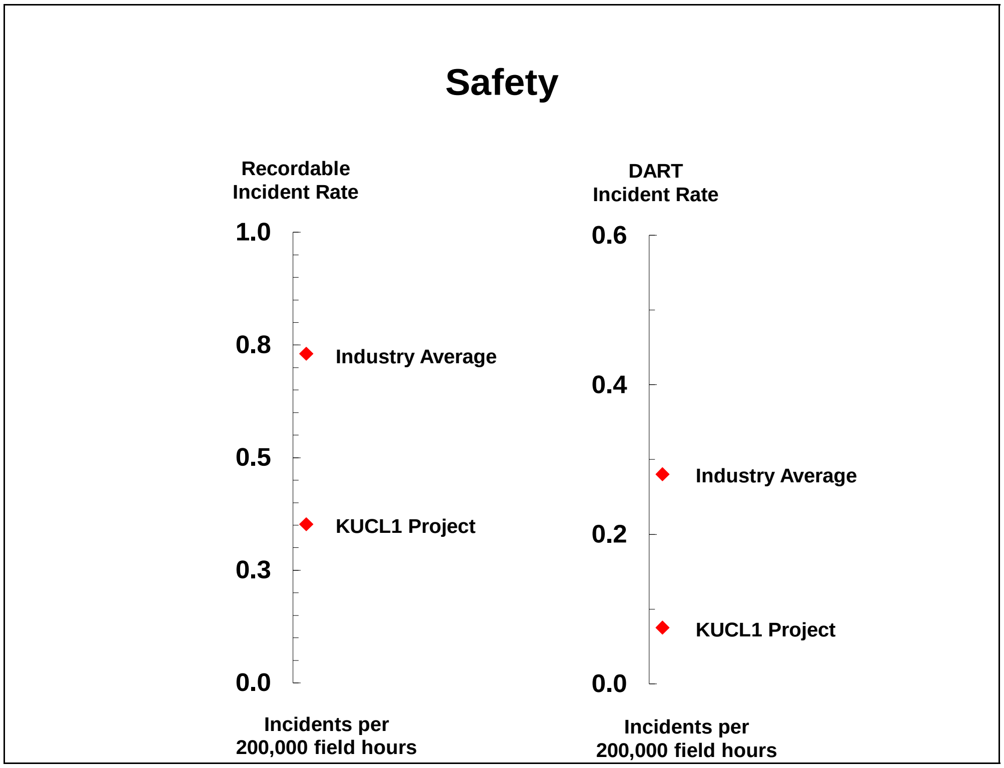


Figure 3

Figure 3 shows the KUCL1 Project's safety relative to industry norms.[19] The KUCL1 Project had four incidents that required days away from work in 14.2 million man-hours which is the equivalent of a Days Away, Restricted or Transferred (DART) incident rate of 0.06 per 200,000 field hours; this rate is lower than the downstream industry average of 0.28 DART incidents per 200,000 field hours. The KUCL1 Project also had 25 recordable incidents for a rate of 0.35 per 200,000 field hours, which is also better than the industry average of 0.73 recordable incidents per 200,000 field hours.

Three of the four LTI's were recorded by drilling while one of those incidents was not directly related to drilling operations. Just over one million manhours were expended on drilling operations, the same as on offshore construction operations which recorded just one LTI. There were no LTI's during onshore construction work but there were 18 recordable incidents in over 12 million manhours.

[19] The industry average is based on IPA's downstream safety data and is provided as a reference point.

Facilities Cost Outcomes

Figure 4 through Figure 10 exhibit the estimated and actual outcomes for the KUCL1 Project's CPP (KAKG-A with KAV-A), WHPs (KUJT-A and F9JT-A), Kanowit subsea system including the 24-inch infield flowline to KAKG- A (KASS), the pipelines from Kumang and F9 to KAKG-A, and the export pipeline from KAKG-A to MLNG onshore at Bintulu. Where possible, benchmarks are country-specific, especially for all platforms and pipelines. The subsea model does not make a specific adjustment for Asia and/or Malaysia. Well construction benchmarks are global due to the nature of the contracting environment.

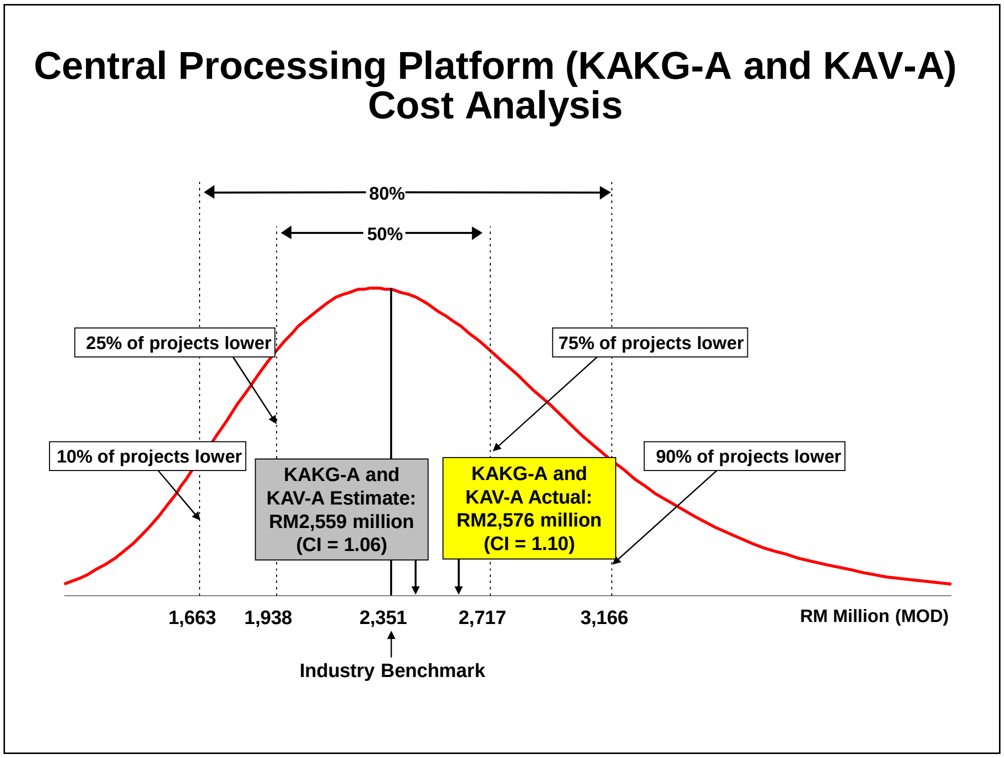


Figure 4

As shown in Figure 4, the KUCL1 Project's CPP (KAKG-A) actual cost was 10 percent higher than Industry. At sanction, the KUCL1 Project's WHP was estimated to be 6 percent more expensive than Industry. Since 2008, IPA's processing platform model has been updated to include a location factor for Malaysia. Also due to the functionality provided by the KAV-A venting platform, the costs of the platform and bridge have been included to compare with similar platforms that may have had a flare boom fitted instead.

As presented in Table 12 and Table 13, topsides weight is in line with industry norms adjusted for Malaysia while the jacket weight is lighter than predicted, which may be due to the flare's location on a separate tripod. Fabrication costs, however, are higher than predicted by IPA's models, resulting in the modestly higher than industry benchmarked cost.

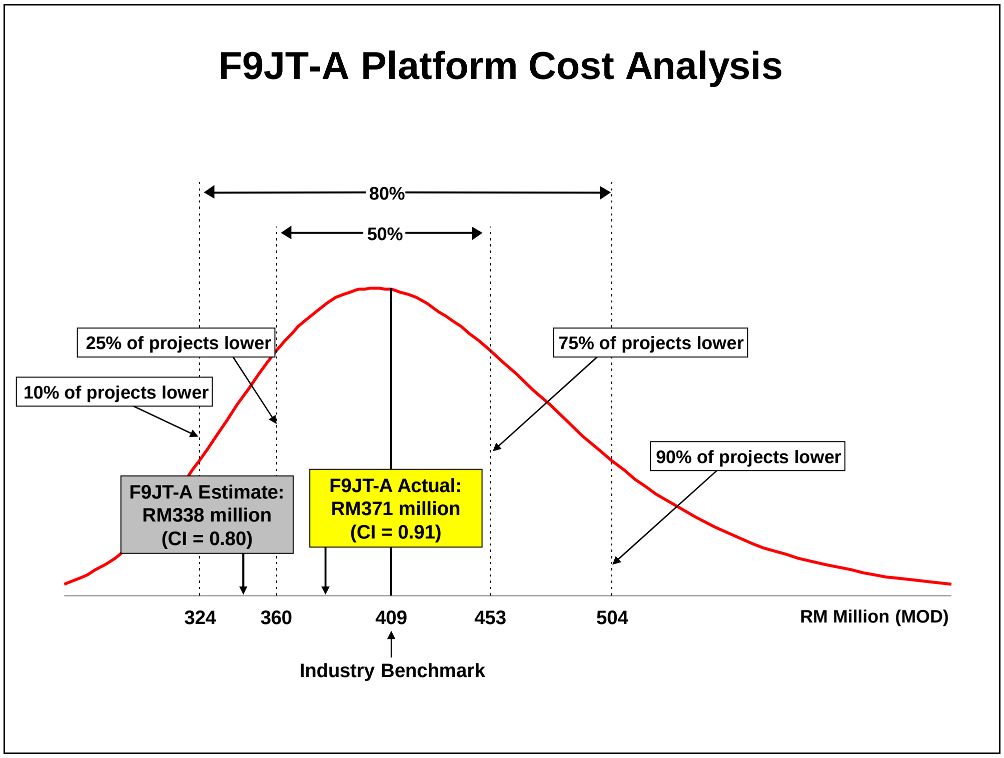


Figure 5

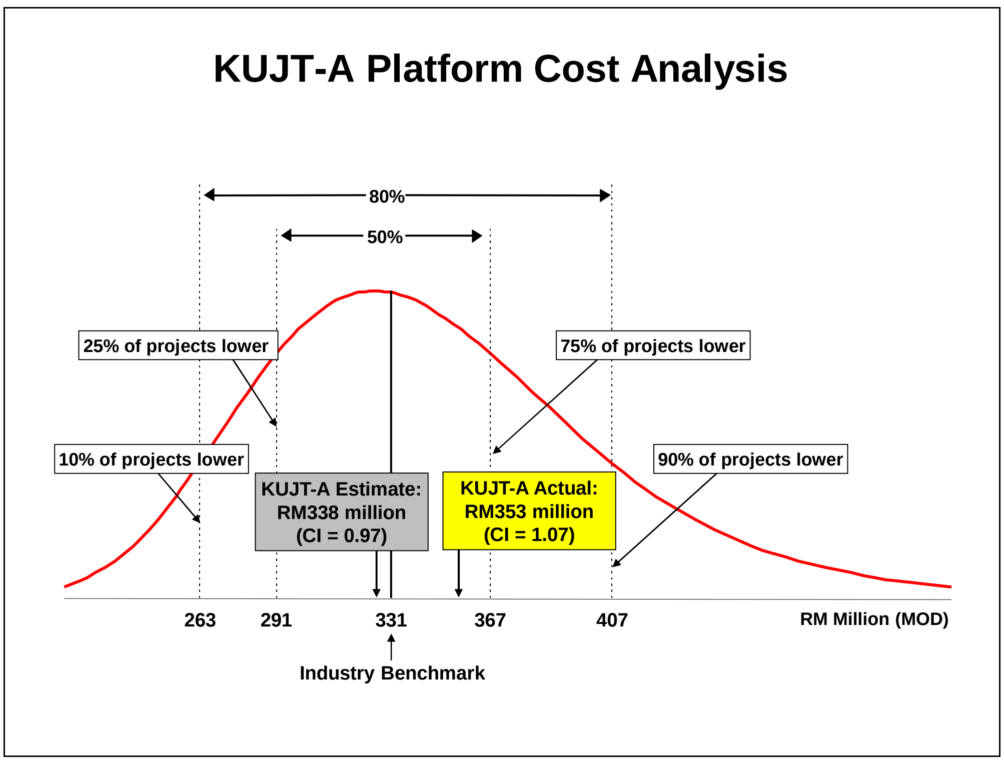


Figure 6

KUJT-A and F9JT-A had similar designs and, as a result, very similar cost estimates and actual costs. IPA's benchmarks suggest opportunities to optimise the Kumang platform design, which was installed in shallower water and had a lower throughput than the F9JT-A platform. While the F9JT-A platform had six slots compared to nine slots at the Kumang platform, IPA's models suggest the number of slots is not the main driver of wellhead platform cost. The F9JT-A platform was installed in 94.8 m waterdepth versus 81.1 m at Kumang, whilst

Kumang has a design throughput of 148 MMscfd and F9 has a design throughput of 350 MMscfd. Consequently, the Kumang platform is considered less competitive than the F9JT-A platform due to a lower benchmark of RM331 million versus RM409 million for F9JT-A.

To provide further insight into platform performance, the jacket and topsides weights, as installed by the KUCL1 project team, were compared with IPA's database (Table 12) revealing that KAKG-A's jacket weight is 30 percent lighter than expected with about industry average topsides weight. Topsides weights for both wellhead platforms seem high, especially for KUJT-A, resulting in higher than expected jacket weight. F9JT-A's jacket weight could not be confirmed from Oilfab's fabrication closeout report.

Table 12
KUCL1 Platform Jacket and Topside Weight Analysis

Platform	Jacket Weight (mt)			Topsides Dry Weight (mt)		
	KUCL1	Predicted	Index	KUCL1	Predicted	Index
KAKG-A	9,998	14,205	0.70	18,800	19,572	0.96
KUJT-A	3,981	3,617	1.10	1,670	991	1.69
F9JT-A	Not Available	4,301	0.93	1,784	1,304	1.37

Fabrication costs for jackets and topsides are presented in Table 13 below for comparison.

Table 13
KUCL1 Platform Jacket and Topside Weight Analysis

Platform	Jacket Fabrication Cost (RM million)			Topsides Fabrication Cost (RM million)		
	KUCL1	Predicted	Index	KUCL1	Predicted	Index
KAKG-A	217.0	152.4	1.42	1,637.0	1,463.6	1.12
KUJT-A	72.0	54.9	1.31	139.0	182.1	0.76
F9JT-A	71.0	59.2	1.20	146.0	195.5	0.75

Table 12 confirms the Kumang platform's topsides weight is higher than predicted and proportionally higher than for the F9JT-A platform, indicating the design practice contributed to the higher cost index for the KUJT-A platform despite lower topsides fabrication cost (for the actual weights installed) as shown by Table 13.

Jacket weight for the KUJT-A platform is in line with expectations. Unfortunately, Oilfab provided no F9JT-A jacket weight for comparison. Jacket fabrication cost was between 20 and 31 percent higher than expected.

As concluded from Table 17 in the appendix, the project suffered cost overruns in T&I and HUC that account for most platforms cost increases.

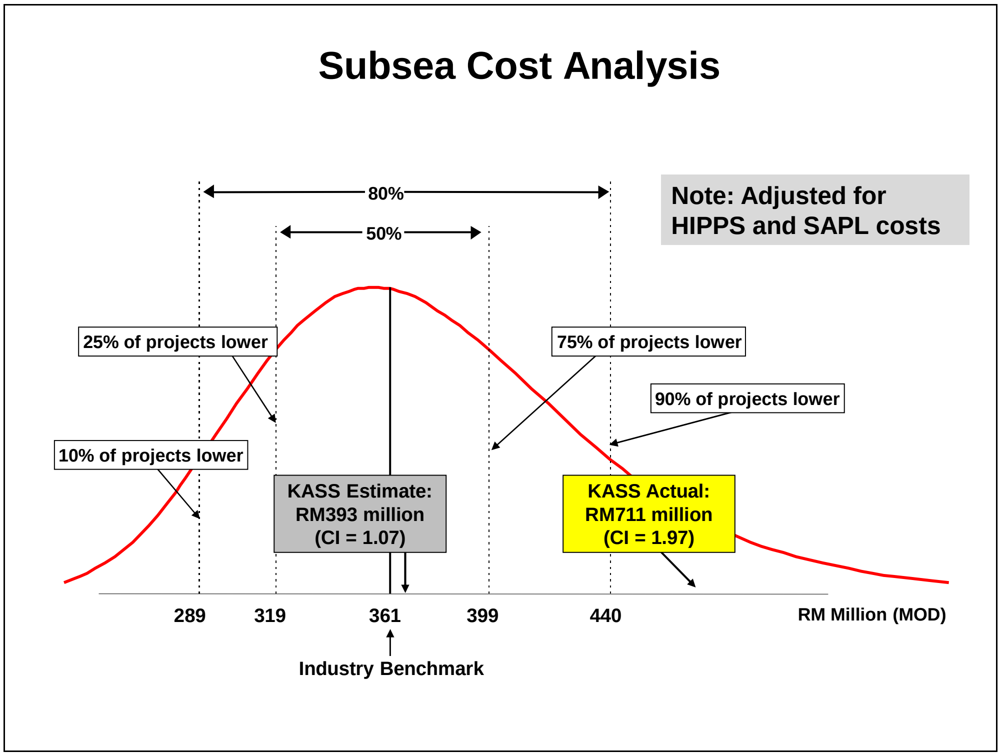


Figure 7

As shown in Figure 7, the KUCL1 Project's subsea cost was higher than industry. However, IPA's cost models do not account for specialty items such as HIPPS and SAPL. IPA was advised that the costs were as follows;

HIPPS = RM31.7 million

SAPL = RM45.5 million

The benchmark includes the cost of the 24-inch x 5 km infield flowline from the PLET to KAKG-A installed in 2011 by Global Offshore Marine (GOM) resources under the PMTIG.

As is clear from the chart above, subsea costs grew substantially as a result of late changes during design to allow for the HIPPS system, SAPL, mattresses, over-trawlable cages to Norwegian (NORSOK) standard, and redesign jumpers from the manifold to the PLET. The subsea automated pig launcher was installed to allow pigging every 3 months, which was a requirement mandated by Petronas Technical Standards (PTS). By having the ability to cover pigging requirements for 1 year, operations costs could be saved by avoiding mobilisation of a subsea intervention vessel. However, this equipment caused the PLET's weight to increase to 180 mt, complicating installation and adding substantial capital cost.

Further cost increases resulted from leaks found after commissioning, which required repair at the projects' expense. Gas leaks were found on the manifold and the hydraulic flying leads and methanol injection line.

IPA Research performed in 2003 and presented at the annual Upstream Industry Benchmarking Conference found that subsea developments that were part of an integrated project experienced greater cost volatility and schedule slip than stand alone subsea tie-back projects and particularly suffered when combined with poor levels of definition prior to project authorisation. The research is briefly summarised in Appendix II.

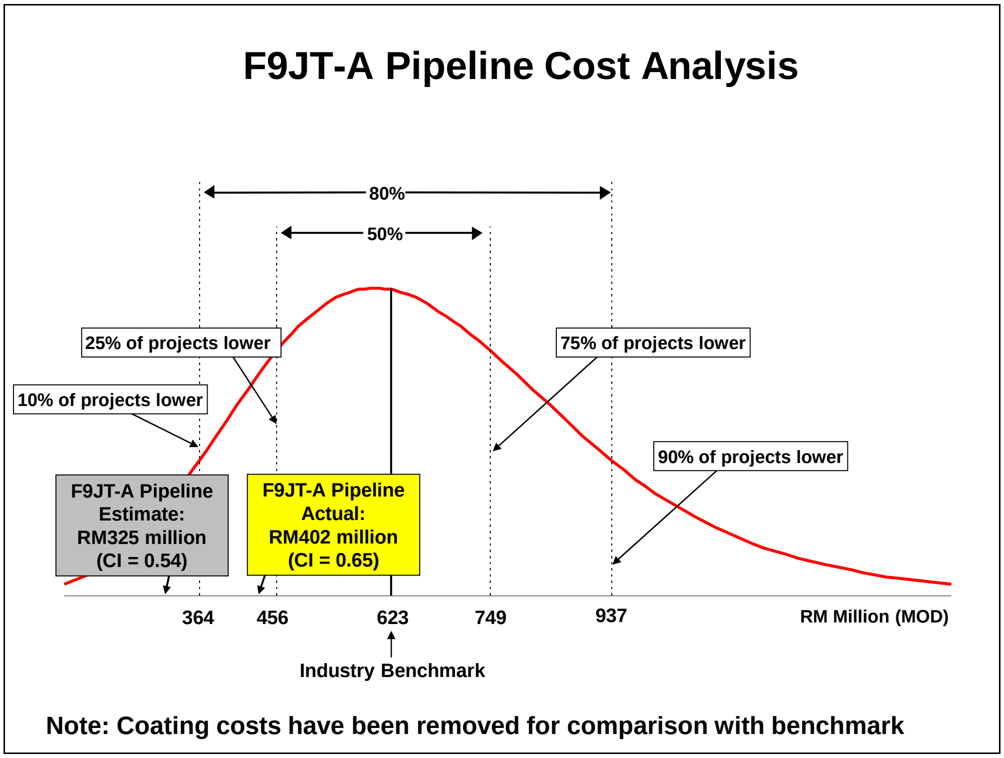


Figure 8

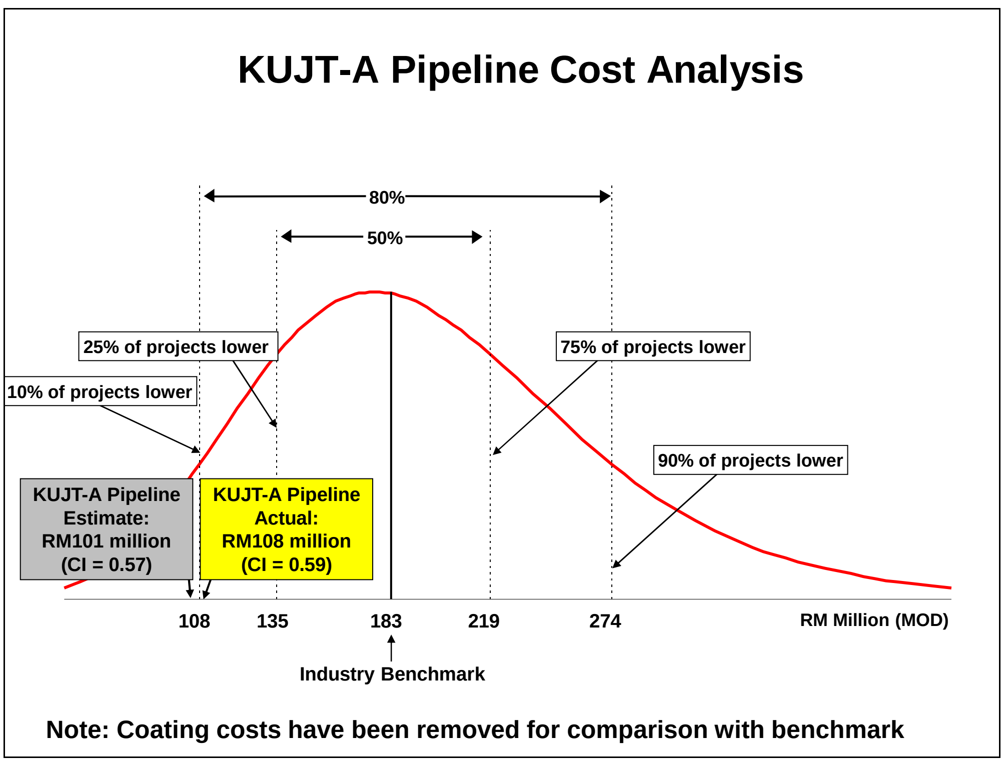


Figure 9

As shown in Figure 8 and Figure 9, the infield gathering pipelines from F9 (28-inch x 57 km) and Kumang (18-inch x 21 km) to the KAKG-A central processing platform were very competitive compared with Industry normalised for Malaysia with between 35 and 41 percent lower capital cost than expected. The pipelines were installed in 2009 under the long-term barge agreement. Line pipe was procured through Mitco Japan in 2007. Costs for concrete coating were removed to compare with the model. The total pipeline installation cost experienced only minor increases during installation.

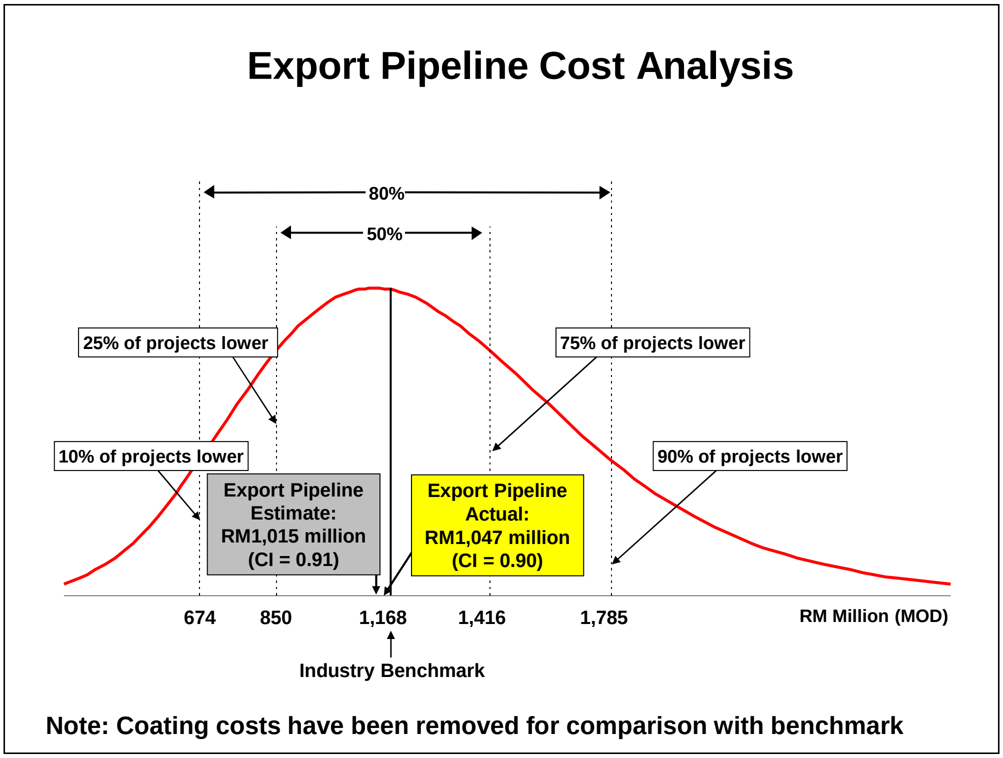


Figure 10

As show in Figure 10, the actual export pipeline (28-inch x 180 km) total installed costs were 10 percent lower than Industry and very much in line with estimates. The export pipeline was also installed in 2009 using the long-term barge contract with line pipe supplied by Mitco Japan. The pipeline was installed in four batches starting at MLNG and moving to KAKG-A.

Well Construction Outcomes

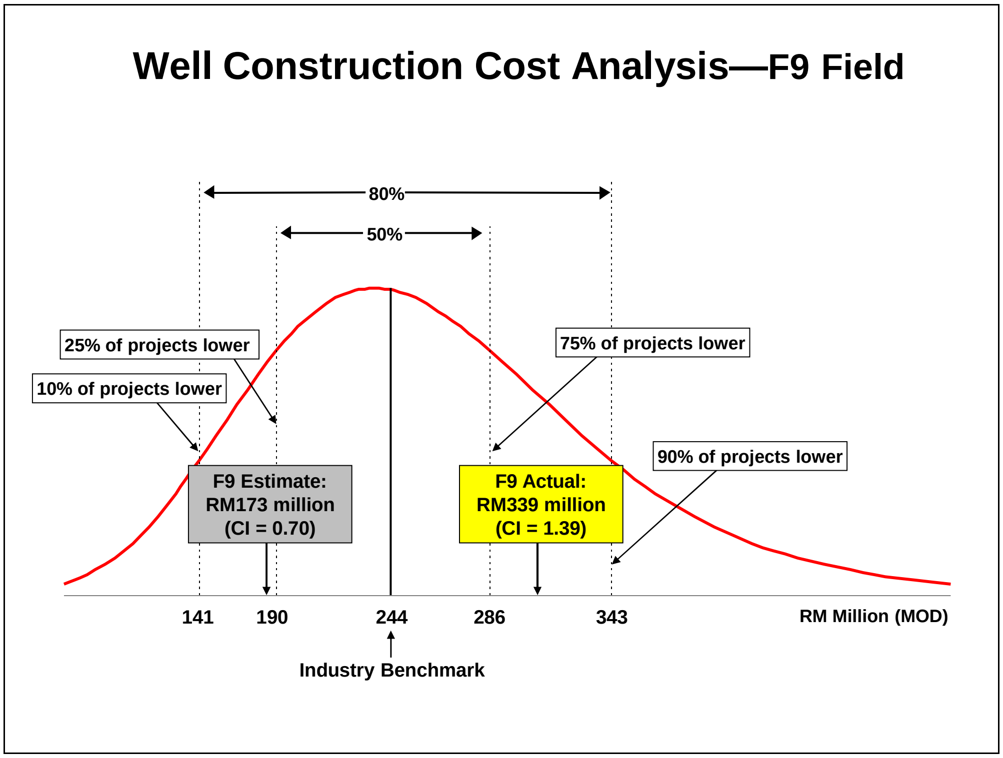


Figure 11

Figure 11 shows the F9 well construction program is 39 percent more expensive than Industry with a significant cost overrun. The F9 wells program initially included four wells, however, only three wells were drilled during the project. F9 was the first field to be drilled for the KUCL1 Project. The cost overrun was caused by the following issues:

- During planning, the team identified a drilling rig for which the wellhead platforms were designed to interface with the tender-assisted derrick barge. After project sanction, this drilling rig was assigned to other projects, and PCSB management assigned the Global Sapphire to KUCL1. This caused interface issues with the F9JT-A platform. Consequently, rig up of the tender-assisted drilling rig took much longer than planned.

- The drilling rig's condition was poor and, once operational, demonstrated significant flaws in topdrive and other essential rig systems reliability. Performance was such that PCSB decided to abort drilling operations after drilling only two wells, prior to the start of the monsoon season to send the drilling rig to dry dock for repairs. Drilling on F9 resumed after repairs were made, and the monsoon had passed.

- The project used three infield support vessels but only two had been allowed for which added to the overspend.

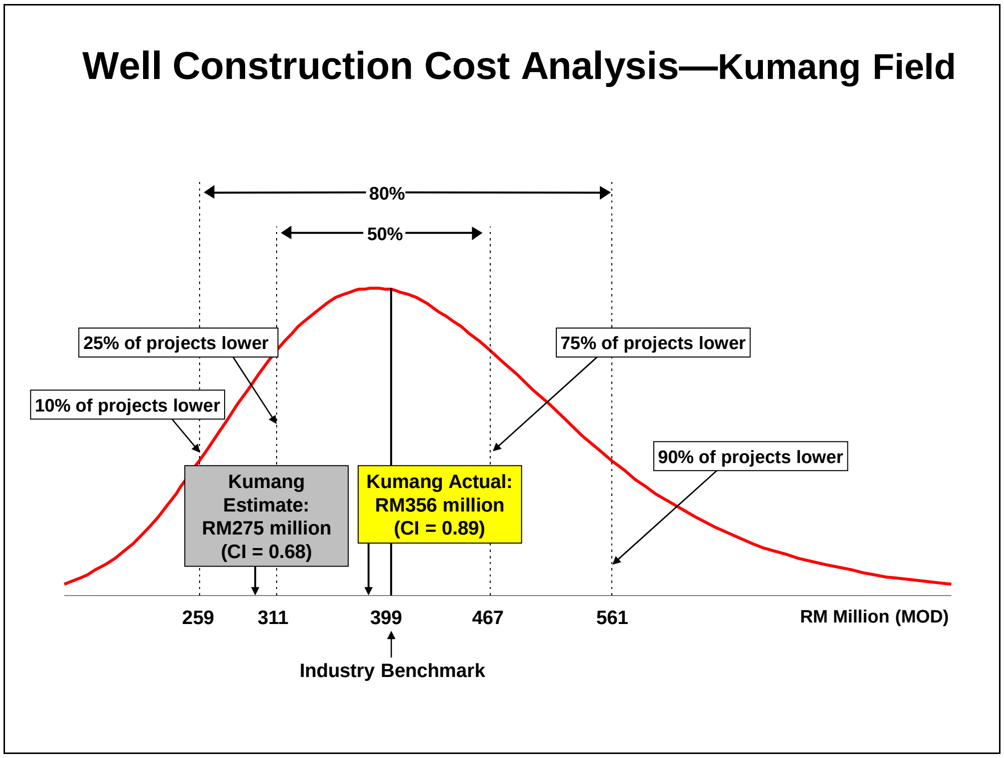


Figure 12

Figure 12 shows the wells program at Kumang was more effective than Industry, although it cost more than planned. The well program consisted of five platform wells with dry trees and open hole gravel packs for the horizontal wells in the Kumang sandstone reservoir.

The Kumang wells were drilled after the Global Sapphire underwent repairs and were therefore drilled more efficiently than the F9 wells. One of the wells was more complex to drill than the others to allow for extended reach drilling which was more challenging than planned.

One well was drilled in its entirety and encountered difficulties in drilling the 12 ¼-inch hole section which experienced hole stability issues and caving while pulling out of hole. Topholes were subsequently batch drilled with water-based mud (WBM) and lower sections were drilled in sequence with synthetic-based mud (SBM). Reservoir pressure was lower than expected which caused losses during cementing and adjustments were made to the well program in casing setting depth and a multi-stage cementing approach.

Four wells were completed with open hole gravel packs in 400 m horizontal, open hole sections. One well was completed with a standalone screen, and all wells had 4 ½-inch tubing with 13Cr.

The project recorded one lost time incident when a worker used the swing rope to transfer to the KAKG-A platform and accidentally landed in the water and injured his back.

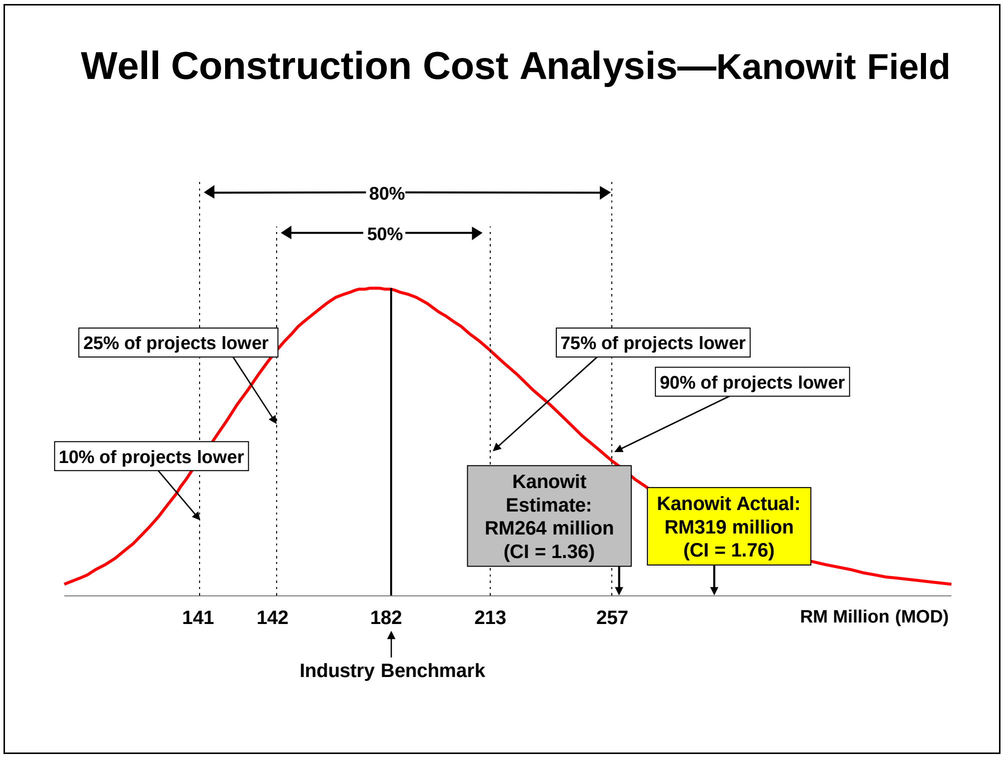


Figure 13

As seen in Figure 13, the KUCL1 Project's Kanowit wells costs were 76 percent higher than Industry and 21 percent higher than planned.

Two subsea wells with horizontal subsea trees and 7-inch monobore completions were installed on Kanowit. While no team members who had direct involvement with the Kanowit drilling campaign were available, the following issues that contributed to the observed performance were identified:

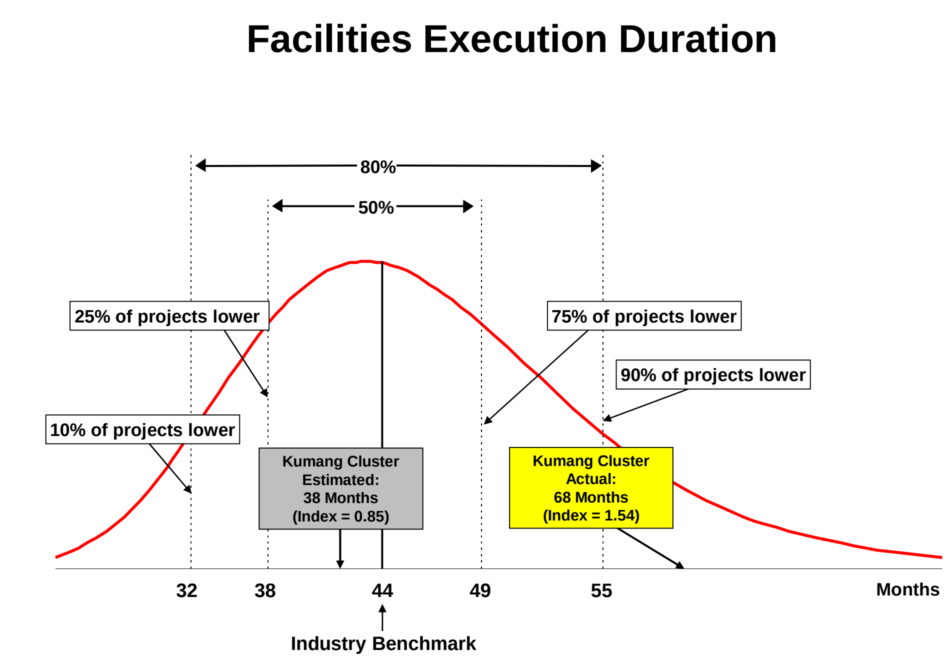
- Subsea tree installation was required to be performed by a subsea intervention vessel because the weight (45 mt) of the large bore (7-inch) trees could not be lifted by the drilling rig. Because the wells weren't spaced far enough apart to continue drilling operations during tree installation, the rig was suspended. According to plan, tree installation would take 5 days but the actual duration was 2 weeks.

- The carbonate reservoir at Kanowit required drilling with 15 pounds per gallon (ppg) mud and an exotic brine to minimise losses. Significant losses were an issue during cementing because of the high reservoir pressure.

- Reservoir temperatures were 95°C, which was much higher than the expected 60°C, complicating drilling and causing one well to be shut-in to avoid exceeding design conditions and later choked back after it had been found safe to produce at 50 percent of full capacity.

- Well testing and stimulation took longer than planned to achieve the productivity required with acid stimulation and cleanup.

Facilities Execution Duration Outcomes



Note: First gas was achieved in August 2011 (46 months after start of detailed design)

Figure 14

The KUCL1 Project estimated facilities execution duration was 15 percent faster than industry norms (see Figure 14). Due to delays throughout project implementation, the KUCL1 Project's facilities duration was 24 months (or 54 percent) longer than the industry average of 44 months, as measured from the start of detailed design in October 2007 through project completion on 30 June 2013. Whilst the project was officially completed in June 2013, repair work on the export pipeline and commissioning work on the KAKG-A platform were still ongoing.

The project would have been more predictable had the Kanowit field been developed as a platform development, in which case project completion in mid-2012 would have been likely and would have been 27 percent slower than Industry.

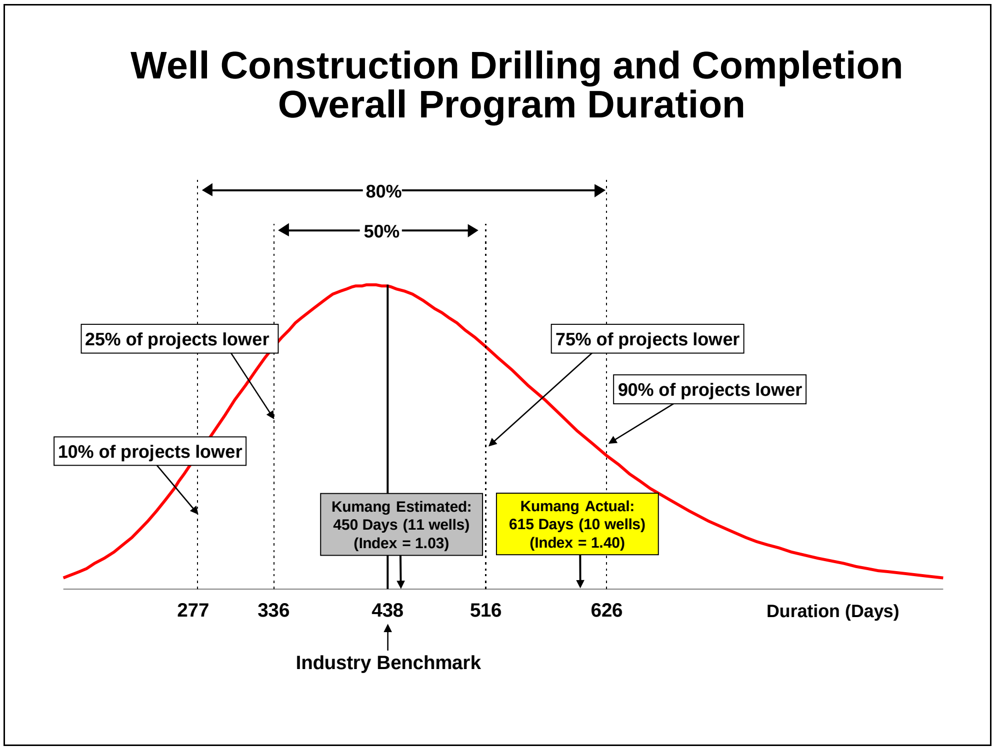


Figure 15

Well construction duration was 615 days or 165 days longer than planned after adjusting for the 5 months the Global Sapphire was out of service for repairs and waiting out the monsoon season. The well construction program took 177 days longer than Industry and incurred longer drilling durations on each field.

Asset Predictability

From initial cost estimates in September 2008 to project completion, the KUCL1 Project experienced facilities cost growth of 11 percent and was 5 percent more expensive than Industry on a weighted average basis for facilities. Platform cost performance was in line with industry average, with increases in T&I and HUC costs. Pipeline performance was competitive despite challenges during pipeline installation because of monsoon season constraints while subsea execution accounted for much of the cost overruns and schedule delays. The schedule slipped by more than 80 percent and exceeded Industry by 54 percent.

Drilling costs grew by 42 percent and took 165 days, or 37 percent, longer than planned. If adjusted for scope, the wells costs grew 57 percent and slipped 50 percent.

Production performance and reserve estimate variations are discussed in Table 14 and the accompanying paragraph following.

Resource Promise Estimate Outcomes

Table 14
KUCL1 Project Resource Promise Estimate (RPE) Metrics Summary

Outcome Metric	KUCL1 Project		Industry Average[20]	PETRONAS Average[21]
	Estimated at FID	Actual		
Change in RPE Between Sanction and First Production		Kumang: +56 percent Kanowit: -26 percent F9: -26 percent Overall: -6 percent	-8 percent	-42 percent
Likelihood of Significant (at least 20 percent) RPE Downgrade	Kumang: 38 percent Kanowit: 46 percent F9: 52 percent		26 percent	25 percent
Production Attainment in Months 7-12 *(unadjusted)*	100 percent 500 MMscfd	0 percent 0 MMscfd	79 percent	41 percent[22]
Production Attainment in Months 7-12 *(adjusted)*		56 percent 281 MMscfd		

As shown in Table 14, the KUCL1 Project's RPE decreased by 6 percent over sanction estimates. The estimated RPE was 309 MMBOE; the actual RPE is 284 MMBOE.

At the project interview, 36 months of production data were available. For the KUCL1 Project, the staggered ramp-up of Kumang and Kanowit severely affected production attainment results, as measured by IPA in months 7 through 12 after start-up. In terms of the unadjusted[23] production attainment in months 7 through 12, the KUCL1 Project delivered 41 MMscfd throughput against its plan of 500 MMscfd. When controlling for the schedule delays, the KUCL1 Project's adjusted production attainment in months 7 through 12 is 56 percent. The KUCL1 Project production attainment outcomes lag both the industry and exceed PETRONAS norms of 79 percent and 41 percent, respectively.

In addition to project delays, the following issues adversely affected production attainment:

- Early onset of water production on F9
- Reservoir temperature on Kanowit exceeding design requiring a shut-in of production and reduced production rates
- Several subsea leaks involving loss of containment of hydraulic fluid, methanol and hydrocarbon gas
- Commissioning issues including: compressors and printed circuit plate heat exchanger (which was a new technology implemented on this project)
- Lower than planned gas demand from MLNG

[20] As reported at UIBC 2013.
[21] As reported at UIBC 2013.
[22] Adjusted production attainment.
[23] Unadjusted production attainment does not adjust for the first gas delay (against sanction targets). At sanction (November 2008), the project's first gas target was 1 May 2011.

The first two issues relate to insufficient or incorrect basic data resulting from an *Aggressive* appraisal strategy. The remaining issues are referred to shaping issues such as the application of new technology and identifying market requirements. Both basic data and shaping issues have been identified by IPA[24] as fundamental to megaproject success.

[24] Merrow, Edward W.; Industrial Megaprojects, Concepts, Strategies, and Practices for Success, Wiley 2011

PROJECT DRIVERS

Table 15
KUCL1 Project's Practices and Drivers Summary

Driver or Practice		KUCL1 Project (Sanction– Feb 2008)[25]	KUCL1 Project (Closeout– Oct 2014)	Industry Average	PETRONAS Average	Best Practice
Appraisal Strategy	**- F9 - Kumang - Kanowit**	*Aggressive*	*Aggressive*	*Conservative*: 40 percent *Moderate*: 37 percent *Aggressive*: 23 percent	*Conservative*: 50 percent *Moderate*: 33 percent *Aggressive*: 17 percent	Not applicable
Reservoir Complexity	**- F9 - Kumang - Kanowit**	28 19 24	26 20 24	39	48	Not applicable
Wells Complexity	**- F9 - Kumang - Kanowit**	22 36 35	22 36 (x 4), 42 35	56	47	Not applicable
FEL Index – Asset		6.40 (*Fair*)	No change	6.21 (*Fair*)	5.81 (*Poor*)	4.50 – 5.50
- **Reservoir**		6.01	No change	5.83 (*Fair*)	5.13 (*Good*)	4.50 – 5.50
- **Wells**		6.00	No change	5.80	5.55	6.13
- **Pipelines**		7.00 (*Poor*)	No change	6.14 (*Fair*)	7.50 (*Poor*)	4.00 – 4.75
- **Facilities**		6.95 (*Fair*)	No change	6.73 (*Fair*)	6.05 (*Good*)	4.00 – 4.75
Team Development Index (TDI)[26]		*Poor*	*Undeveloped*	*Fair*	*Fair*	*Good*
Team Integration (including Operations)		*Not Integrated*	No change	56 percent of Projects Integrated	29 percent of Projects Integrated	Yes
Technical Innovation of Facilities		*Conventional*	*Substantial*	*Conventional*: 79 percent *Moderate*: 18 percent *Substantial*: 3 percent	*Conventional*: 43 percent *Moderate*: 83 percent *Substantial*: 17 percent	Not applicable
Technical Innovation of Wells		*Moderate*	No change	*Conventional*: 72 percent *Moderate*: 25 percent *Substantial*: 3 percent	*Conventional*: 80 percent *Moderate*: 20 percent *Substantial*: 0 percent	Not Applicable
Percentage of Facilities VIPs Used		30 percent	No change	24 percent	7 percent	40 – 60 percent
Percentage of Subsurface VIPs Used		50 percent	No change	37 percent	61 percent	

Table 15 summarises the KUCL1 Project practices and drivers at sanction (Tier 1) in February 2008 as assessed during this closeout evaluation (October 2014). The KUCL1

[25] As measured at IPA's prospective evaluation in December 2008. Whilst the project received full funds authorisation in September 2008, IPA measures the definition for this evaluation at the pre-funding approval in February 2008.
[26] Team development takes into consideration the project objectives' clarity and project team's acceptance of the objectives. In hindsight, the project's objectives were not clearly stated and agreed between all stakeholders.

Project drivers and practices as assessed during the prospective evaluation (September 2008) are also shown. IPA measures the level of definition at the Tier 1 sanction milestone because at that time PCSB committed RM595 million to the project which was 11.1 percent of the total estimated cost for the project at this time which was RM5.4 billion). IPA considers the project '*De Facto*' authorised when more than 10 percent of the project's estimated capital has been committed.

For detailed descriptions of driver ratings, please refer to the October 2010 prospective report. We describe in detail below only the drivers whose ratings have changed for the KUCL1 Project. The industry and PETRONAS averages at sanction as reported at UIBC 2013 are also included for reference.

The KUCL1 Development Project was a schedule-driven project with mixed objectives and, despite an advanced level of engineering, lacked the proper planning and recognition of potential project risks posed by an *Aggressive* appraisal strategy and application of technology new to the company. Moreover, the project did not have a well-staffed, integrated team with a single point of accountability which allowed key decisions (such as drill rig and installation contractor selection) to be made outside the project team's direct control.

Therefore, in IPA's closeout assessment, the following ratings were amended.

Team Development Index (TDI); This index measures team development on four criteria: clarity and acceptance of project objectives by all stakeholders, team integration, definition of roles and responsibilities, and the existence of and adherence to an established project implementation process. IPA rated TDI as *Poor* at the prospective evaluation but has now downgraded this rating to *Undeveloped*. At the prospective evaluation, IPA accepted that project objectives were clear and understood by all stakeholders. However, in hindsight, the project drivers appear to have been poorly defined and quantified. As confirmed by project team members, the project did not pass through a proper opportunity framing process. The project's economics were, at best, marginal, and this was the first PCSB-operated project in Malaysia of strategic significance. The project was schedule driven to meet gas demand and sacrificed further data-gathering, leaving the project vulnerable from an *Aggressive* appraisal strategy. Full-funds authorisation was delayed until after detailed design was complete to improve cost predictability but in the absence of thorough project execution planning evidenced by the absence of a project execution plan prior to 2010. Failing to recognise the project's complexity, Petronas decided to change the concept for Kanowit to a subsea development to obtain in-house capability to perform subsea projects. It is unclear why this project was the right vehicle to obtain such expertise rather than perform a subsea project on a reservoir from which more information was available and which could be done in isolation, free from schedule pressure and megaproject complexities.

Technological Innovation of Facilities was rated *Moderate* at the prospective, but the late changes, particularly in subsea, added significant new technology and technology new to the team. In particular, the subsea automated pig launcher was *Substantial* New Technology which elevated the project's risk of cost growth, schedule slip, and operability problems. Other new technology included plate heat exchanger technology on KAKG-A topsides to cool the gas prior to export compression.

PROJECT EXECUTION DISCIPLINE

Table 16
KUCL1 Project's Execution Discipline Summary

Project Execution Discipline	KUCL1 Project	Industry Average	PETRONAS Average	Best Practice
Project Control Index (PCI)	*Deficient*	*Fair*	*Fair*	*Good*
Major Late Changes	Yes	75 percent of projects	50 percent of projects	None
Project Manager Turnover	Yes	75 percent of projects	50 percent of projects	None

Project Control Index

IPA research shows that projects with strong project cost and schedule control practices have less cost growth and schedule slip and have a lower probability of late changes. During definition, project control supports achieving *Best Practical* FEL by establishing effective cost and schedule control baselines. During execution, project control maintains cost and schedule discipline to ensure planned outcomes are achieved. The benefits of good FEL can be significantly eroded by poor project control practices during execution.

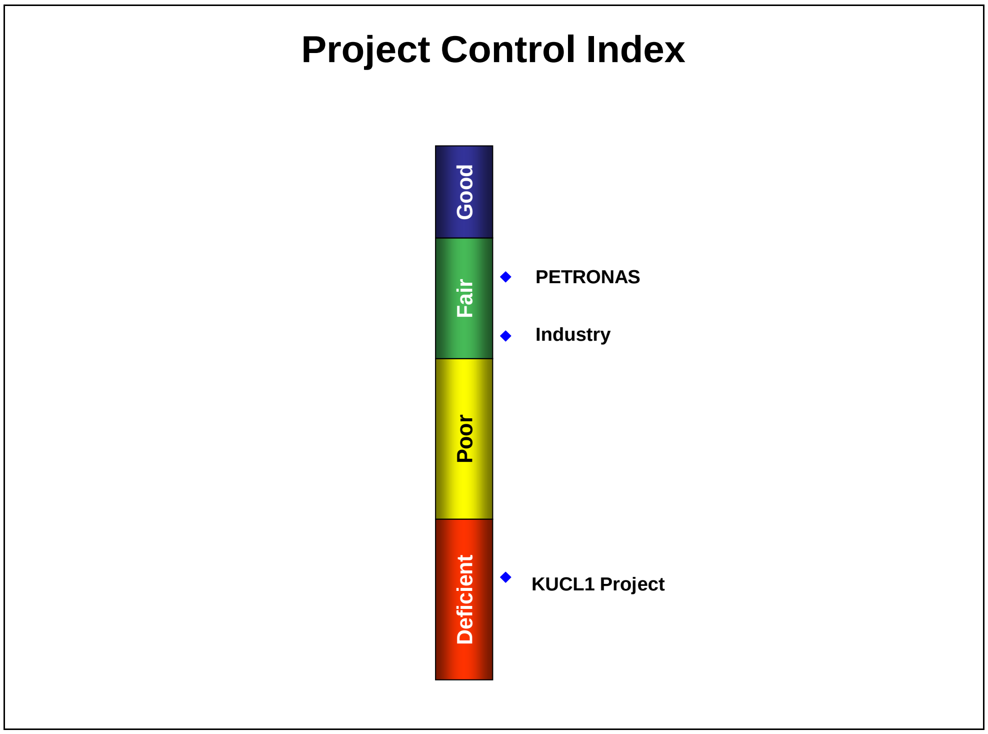


Figure 16

As shown in Figure 16, the KUCL1 Project had an actual Project Control Index (PCI) in the *Deficient* range, which is worse than industry and PETRONAS averages, both *Fair*. The company did not establish a project controls department or systems until 2010 when the project was well underway, and a large part of project execution had, in fact, been completed.

Major Late Changes

A change is defined as a deviation from the project's planned configuration, objectives, or desired functionality. Changes can be grouped under design or scope changes. Design changes do not involve a change in functionality or business objectives. Scope changes are a change to the business objectives or desired functionality.

IPA measures as a major late change any design and/or scope change that takes place after sanction that costs or saves the equivalent of 0.5 percent of the sanction estimate or causes at least 1 month of schedule delay or acceleration. We exclude changes to the project's execution strategy and changes driven by external factors such as weather or strikes from our major late changes definition. Moreover, IPA does not consider either cost trending or rework, which are often captured in project change logs, as project changes. Based on these criteria, the KUCL1 Project had two major late changes:

1. KAKG-A topsides design changed from an integrated deck to a modular design which particularly affected the main support frame which was split into three sections. Overall weight increased (from 17,000 to more than 18,500 mt) and more heavy lifts were required albeit with a smaller heavy lift barge (up to 3,000 mt) since there were no barges available that could perform the heavy lift of the integrated topsides. This change might have been avoided if the lack of available lift vessels had been identified during FEED in the course of developing an integrated project schedule and project execution plan which had not been prepared for the project until as late as 2010.

2. Kanowit subsea changes:

    a. Higher than expected reservoir temperature caused operating conditions to exceed design limits. This required the subsea system to be shut-in for several months and re-started at reduced rates following validation by Det Norske Veritas (DNV)

    b. Mattresses added for jumpers

    c. Protective covers design changed to NORSOK standard

    d. Addition of subsea HIPPS

    e. Addition of Subsea Automated Pig Launcher

    f. Design throughput changed from 100 MMscfd to 150 MMscfd

    These changes were the result of incorrect reservoir data and changes in company technical requirements. While insufficient information is available to qualify the work done by the project team on the subsea FEED some issues might be the result of inexperience with the technology and a lack of understanding of operational consequences of design decisions made during FEED.

3. F9 well program comprised three wells instead of the four planned wells

Team Turnover

Recent IPA research[27] shows turnover in *one* critical function affects cost effectiveness by 6 percent and schedule effectiveness by 10 percent. The results are further exacerbated by *more than one* turnover, which affects cost effectiveness by 30 percent and schedule effectiveness by 27 percent.

The KUCL1 Project experienced a high degree of team member turnover, including the project manager position, and recorded a cost overrun (11 percent) and schedule slip (81 percent).

The KUCL1 Project did not have an integrated project team with a single point of accountability. Significant turnover occurred late 2009 after installation of most structures and pipelines. Project team cohesion suffered when major scope was completed and activity focus shifted to installation, subsea, drilling and hook-up and commissioning. It was then that the project was re-baselined and experienced significant cost growth and schedule slip.

[27] Kate Rohrbaugh and Katya Petrochenkov, *Maintaining Team Stability: How to Prevent Total Disaster,* IBC 2011, IPA, March 2011.

CONCLUSIONS AND LESSONS LEARNED

The KUCL1 Project's mixed results showed better than industry safety outcomes, competitive pipeline and wellhead platform costs, and a significant reserve increase on Kumang. However, the project achieved first gas 9 months late and dragged on for 2 years due to significant changes and installation issues related to subsea equipment. Costs grew as a result of problems with the drilling rig, unplanned changes to subsea hardware design, and problems during installation which included several subsea leaks. Production attainment has been significantly lower than planned due to reserves downgrade on F9 and Kanowit, operability issues with the subsea system and central processing platform, F9 reservoir performance and lower than planned gas demand.

The project's objectives appear to have been poorly defined and quantified due to the lack of a formal opportunity framing process. The project economics were, at best, marginal but yet, the project was schedule driven to meet gas demand and sacrificed further data gathering, leaving the project vulnerable from an *Aggressive* appraisal strategy, lacking comprehensive and accurate basic data. Failing to recognise the project's complexity, Petronas changed the concept for Kanowit to a subsea development to obtain in-house capability to perform subsea projects. It is unclear why this project was chosen to obtain such expertise rather than perform a subsea project on a reservoir from which more information was available and which could be done in isolation, free from schedule pressure and megaproject complexities. However, had the project been adequately resourced and applied best practice by fostering team integration and the development of a comprehensive project execution plan some of the issues observed might have been prevented.

Based on IPA's analysis of historical industry performance and assessment of the KUCL1 Project, we offer the following key lessons for consideration on future PETRONAS projects.

PROJECT LESSONS LEARNED

1. ***Aggressive appraisal is coupled with greater reserves volatility and uncertainties with regard to facilities design***. The Kumang Cluster Phase 1 Project had an *Aggressive* appraisal strategy and experienced 26 percent reserves downgrades on the Kanowit and F9 reservoirs. Fortunately, Kumang made up a large part of this with a 56 percent reserve increase; however, production from Kumang is now constrained to 148 MMscfd by its infield flowline. Furthermore, aggressive appraisal led to operability problems with the subsea system when the reservoir temperature at Kanowit was higher than expected, exceeding the subsea tree's temperature rating and requiring the well to be shut-in.

2. ***Set clear objectives*****.** The lack of clear objectives and stakeholder alignment allowed two key decisions to be implemented without challenge that eroded the potential for the KUCL1 Project to achieve success. These decisions included assigning a different tender assisted drilling rig and developing Kanowit as a subsea development. Both decisions lead to severe schedule slip, cost growth, and operability problems. With clear objectives and accountability for outcomes, these decisions would have been scrutinised more closely and would likely have been avoided. An Opportunity Framing Process is widely used in Industry to gain alignment around project objectives by a wide group of stakeholders.

3. ***Focus on project execution planning not just detailed design to achieve predictable and competitive outcomes.*** Curiously, the project team changed its contract strategy from EPCC to award a PC contract after detailed design to avoid late changes, but there was no Project Execution Plan in late 2008. The Project Execution Plan is a key document for any project and serves as the basis for the project team to effectively progress into each phase. Without this document, team

integration and alignment was difficult to achieve. Kumang Cluster Phase 1, was schedule- and resource-constrained, and having a Project Execution Plan to bind the team and stakeholders to project goals is critical. In addition, taking the time and effort to prepare a Project Execution Plan might have highlighted the unavailability of heavy lift barges capable of lifting the integrated KAKG-A topsides thereby avoiding a late change in execution to split the main support frame and process packages and it might have revealed the project complexities to rationalise the decision to develop Kanowit with a subsea system rather than a wellhead platform.

4. ***Build integrated project teams.*** Integrated project teams in upstream asset developments are critical, because important information needs to be shared on a continuous and repetitive basis to lead to successful outcomes. Subsurface data, whether accurate or with a range of uncertainty, must be shared with facilities engineers and drilling personnel. Project plans need to be updated and communicated so other functions can respond to changes and the many interfaces between various parts must be adequately managed. IPA research has demonstrated the link between project team integration and successful project outcomes.

5. ***Concept selection should clearly weigh all aspects of project development including cost, schedule operability, and risk, and decisions should be clearly documented.*** The Kumang Cluster Phase 1 Project installed a two-well subsea system on the Kanowit field in 77 m water depth. The company had no experience with subsea systems and was implementing its first major project in Malaysia, which was schedule driven and had an *Aggressive* appraisal strategy. The subsea system required a separate semi-submersible drilling rig to be mobilised, required significant implementation of new technology, and suffered from inaccurate subsurface data. Whilst benchmarks clearly show a solution involving a wellhead platform and drilling with the tender assist would have been more cost effective (probably also in operation), if the objective was to learn, then it might have been better to consider the project as a stand-alone tie-back to the CPP without the schedule pressure and added complexity of a megaproject.

6. ***Subsea projects that are integrated with a larger project development typically experience greater schedule slip and cost growth than standalone subsea development projects.*** IPA Research performed in 2003 and presented at the annual Upstream Industry Benchmarking Conference found that subsea developments that were part of an integrated project experienced greater cost volatility and schedule slip than standalone subsea tie-back projects and particularly suffered when combined with poor levels of definition prior to project authorisation. The research is briefly summarised in Appendix II. The KUCL1 subsea component experienced late changes as a result of poor basic data and limited FEED compounded with the lack of a comprehensive project execution plan which led to requirements for new technology leading to schedule slip and cost growth and most importantly lower production than planned.

APPENDIX I: KUCL1 PROJECT COST AND SCHEDULE

PROJECT COST DISTRIBUTION

Table 17 summarises the estimated and actual KUCL1 Project costs using the project team's cost breakdown.

Table 17
KUCL1 Project's Cost Distribution[28] (RM Million MOD)

	KUCL1 Project Estimated (September 2008)			KUCL1 Project Actual (October 2014)		
	Facilities	Export Pipeline	D&C	Facilities	Export Pipeline	D&C
Front-End Loading	12			12		
Detailed Engineering	66	6		61	6	
Project Management	173	47	17	355	86	46
Non-Well Activities			38			130
Fabrication	3,016	661		2,922	619	
Transport and Install	677	420		1,022	443	
Drilling			531			711
Formation and Completions			94			126
Hook-up & Commissioning	215			340		
Other Project Costs			32			
Sub-Total	4,159	1,135	712	4,712	1,154	1,014
Total Installed Asset Cost	6,005			6,879		

PROJECT SCHEDULE

Table 18 summarises the KUCL1 Project schedule. The planned execution schedule was 37.5 months, commencing at the start of detailed design in October 2007 and ending with project completion in December 2010. The actual execution time was 68 months to project completion at the end of June 2013 whilst the duration to first gas from F9 in August 2011 was 46 months.

[28] Numbers may not add exactly due to rounding.

Table 18
KUCL1 Project Schedule

	Planned Schedule			Actual		
	Start	Finished	Duration	Start	Finished	Duration
Petronas Provided Data to PCSB	15 Apr 05			15 Apr 05		
PSC Signed between PCSB and Petronas	15 Sep 05			15 Sep 05		
Field Development Plan - Subsurface Studies	2 Feb 06	15 Mar 07	13.4	2 Feb 06	15 Mar 07	13.4
Conceptual Engineering (FEL 2)	**2 Feb 06**	**22 Mar 07**	**13.7**	**2 Feb 06**	**22 Mar 07**	**13.7**
FDP Approval	22 Mar 07	6 Jun 07	2.5	22 Mar 07	6 Jun 07	2.5
FDP Optimisation (Subsurface and Subsea)	7 Jun 07	2 Jul 08	12.8	7 Jun 07	2 Jul 08	12.8
Decision to Change KAJT-A to Subsea	15 Aug 07			15 Aug 07		
GSA Signed between PCSB and Petronas	31 Dec 07			31 Dec 07		
FDP Addendum - Submit to Petronas	29 Aug 08			29 Aug 08		
Front End Engineering – Define Stage (FEL 3)	**2 Mar 07**	**26 Oct 07**	**7.8**	**2 Mar 07**	**26 Oct 07**	**7.8**
Advance Funding Approval from PCSB	**15 Feb 08**			**15 Feb 08**		
Detailed Engineering	**27 Oct 07**	**29 Aug 08**	**10.1**	**27 Oct 07**	**29 Aug 08**	**10.1**
Project Sanction (Sanction Tier 2)	**25 Sep 08**			**25 Sep 08**		
Procurement PCSB Equipment	4 Jan 07	7 Feb 10	37.1	4 Jan 07	31 Oct 12	69.7
Fabrication - Subsea	27 Sep 08	7 Feb 10	16.3	15 Jul 09	31 Oct 12	39.5
Fabrication (KAKG-A Topsides)	15 Jul 08	1 Feb 10	18.5	13 Sep 08	15 Apr 10	19.0
Fabrication (KAKG-A Jacket)	1 Oct 08	1 Nov 09	13.0	1 Jul 08	24 Aug 09	13.7
Fabrication (F9JT-A Topsides)	15 Jul 08	15 Jul 09	12.0	28 Jul 08	22 Aug 09	12.8
Fabrication (F9JT-A Jacket)	1 Oct 08	1 Aug 09	10.0	15 Sep 08	17 Jun 09	9.0
Fabrication (KUJT-A Topsides)	15 Jul 08	15 Jul 09	12.0	28 Jul 08	8 Aug 09	12.3
Fabrication (KUJT-A Jacket)	1 Oct 08	1 Aug 09	10.0	1 Jul 08	8 Aug 09	13.2
Fabrication (KAV-A and Bridge)	1 Oct 08	1 Feb 10	16.0	15 Sep 08	30 Apr 10	19.4
Loadout (KAKG-A Topsides)	7 Mar 10	5 May 10	1.9	1 May 10	30 May 10	1.0
Loadout (KAKG-A Jacket)	12 Feb 10	21 Feb 10	0.3	3 Sep 09	6 Sep 09	0.1
Loadout (F9JT-A Topsides)	16 Jul 09	25 Jul 09	0.3	29 Aug 09	30 Aug 09	0.0
Loadout (F9JT-A Jacket)	2 Aug 09	11 Aug 09	0.3	10 Jun 09	22 Jun 09	0.4
Loadout (KUJT-A Topsides)	16 Jul 09	25 Jul 09	0.3	15 Sep 09	17 Sep 09	0.1
Loadout (KUJT-A Jacket)	2 Aug 09	11 Aug 09	0.3	15 Sep 09	18 Sep 09	0.1
Loadout (KAV-A)	2 Aug 09	8 Aug 09	0.2	1 Aug 10	1 Sep 10	1.0
Line Pipe Procurement (all except Kumang)	11 Jul 08	15 Mar 09	8.1	6 May 08	26 Mar 09	10.6
Line Pipe Procurement (Kumang)	27 Nov 07	15 Apr 08	4.6	27 Nov 07	15 Apr 08	4.6
Pipeline Installation (Export)	26 Nov 08	7 Aug 09	8.3	5 Mar 09	12 Aug 10	17.2
Pipeline Installation (F9)	10 Apr 09	26 May 09	1.5	2 Jul 09	25 Aug 09	1.8
Pipeline Installation (Kumang)	1 Apr 09	20 Apr 09	0.6	4 May 09	1 Jun 09	0.9
Pipeline Installation (Kanowit)	23 May 09	3 Jun 09	0.4	22 Apr 11	25 May 11	1.1
T&I Platform (2009 Campaign)	26 Jul 09	7 Oct 09	2.4	23 Jun 09	25 Sep 10	15.0
T&I Platform (2010 Campaign)	22 Feb 10	16 May 10	2.8	23 Jun 09	25 Sep 10	15.0
Subsea Installation	11 Oct 10	13 Oct 10	0.1	20 Dec 11	20 Nov 12	11.0
Onshore Tie-in	1 Apr 09	18 Jul 10	15.5	19 Oct 09	24 Aug 11	22.1
Platform HUC	3 Mar 10	12 Dec 10	9.3	5 Mar 10	10 May 12	26.1
Subsea HUC	14 Nov 10	7 Dec 10	0.8	12 Mar 12	31 Dec 12	9.6
Drilling (WHP - TAD)	9 Sep 09	15 Aug 10	11.2	3 May 10	14 May 12	24.3
Drilling (Subsea – Semi-Sub)	8 Feb 10	10 Oct 10	8.1	30 Oct 11	12 Apr 12	5.4
First Gas from F9 Field	**14 Oct 10**			**31 Aug 11**		
First Gas from Kumang Field	**not specified**			**10 May 12**		
First Gas from Kanowit Field	**not specified**			**23 Dec 12**		
Project Completion	**12 Dec 10**			**30 Jun 13**		
Execution Schedule to First Gas	**27 Oct 07**	**14 Oct 10**	**35.5**	**27 Oct 07**	**31 Aug 11**	**46.0**
Execution Schedule to Complete	**27 Oct 07**	**12 Dec 10**	**37.4**	**27 Oct 07**	**30 Jun 13**	**68.0**
Cycle Time	**2 Mar 07**	**12 Dec 10**	**45.3**	**2 Mar 07**	**30 Jun 13**	**75.8**

APPENDIX II: SUBSEA PROJECT PERFORMANCE UIBC 2003

IPA conducted a research study that was presented at the Upstream Industry Benchmarking Conference in November 2003. A brief recap of the main findings is presented here for future reference.

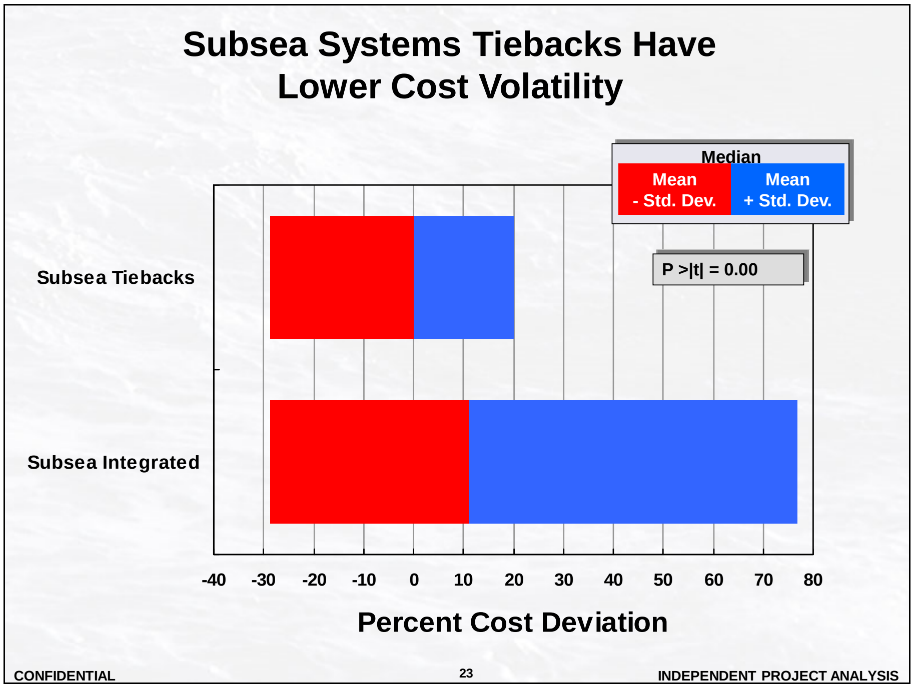


Figure 17

Figure 17 illustrates that subsea tie-back projects have better cost predictability than subsea developments which are integrated with a full asset development. Integrated subsea projects also experience higher cost growth (10 percent on average) with some project experiencing as high as 75 percent cost increase.

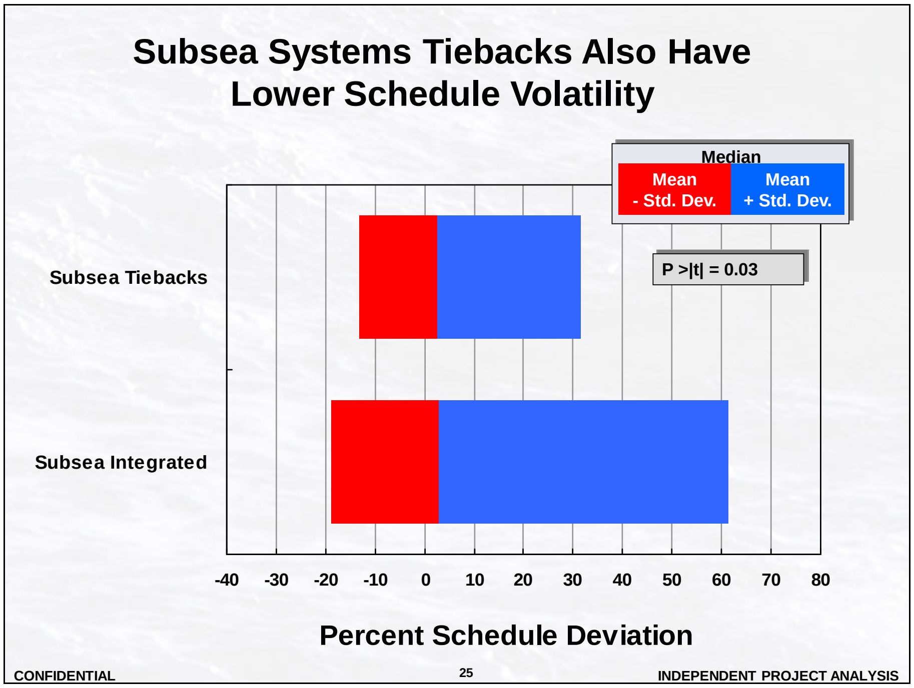


Figure 18

Similarly to cost deviation, Figure 18 illustrates that integrated subsea developments have greater schedule volatility than subsea tie-backs.

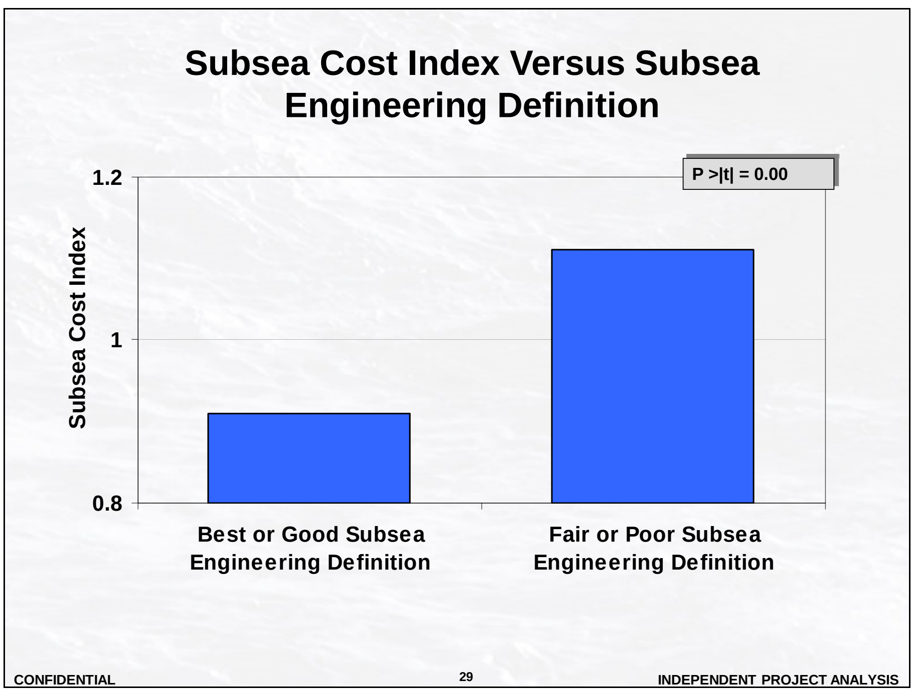


Figure 19

Subsea cost performance is dependent on the level of engineering definition prior to project sanction. Projects with Best or Good levels of engineering definition have a substantially better chance of outperforming Industry by 10 percent whilst poorly defined projects experience uncompetitive cost performance as illustrated by Figure 19.

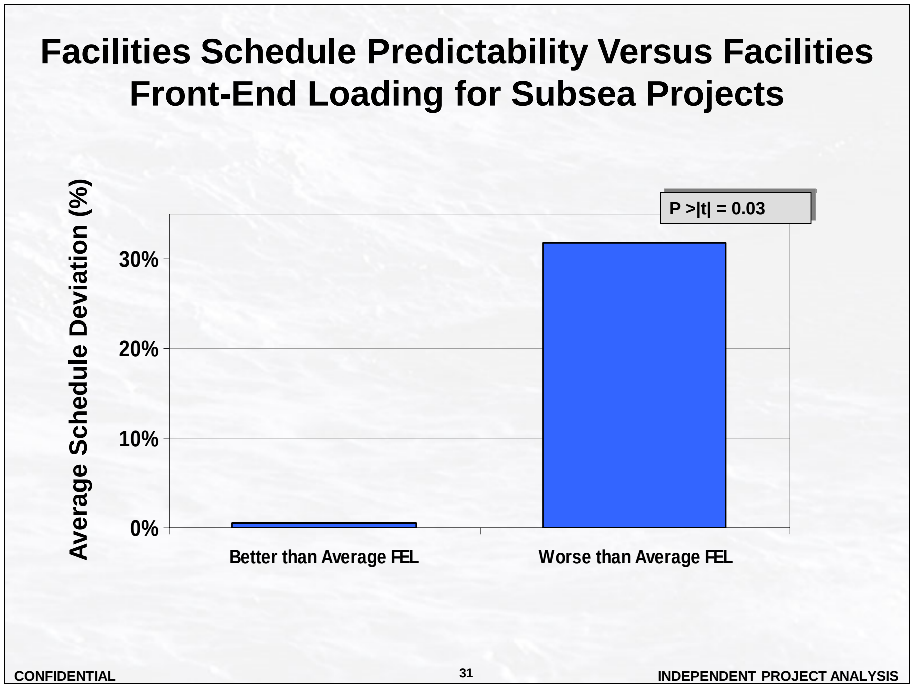


Figure 20

Figure 20 shows the effect of worse than average FEL on schedule performance which can lead to as much as 30 percent schedule slip. FEL encompasses engineering and planning to ensure that the project is well defined prior to sanction. A project execution plan is an essential document to ensure that all stakeholders understand the risks and challenges with the project as well the implementation and risk mitigation strategy.

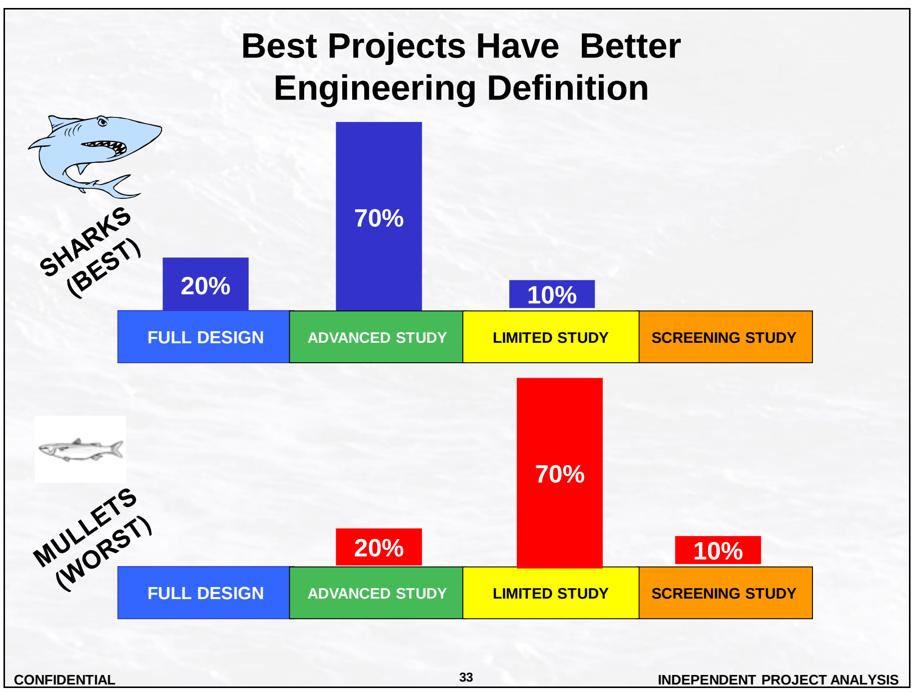
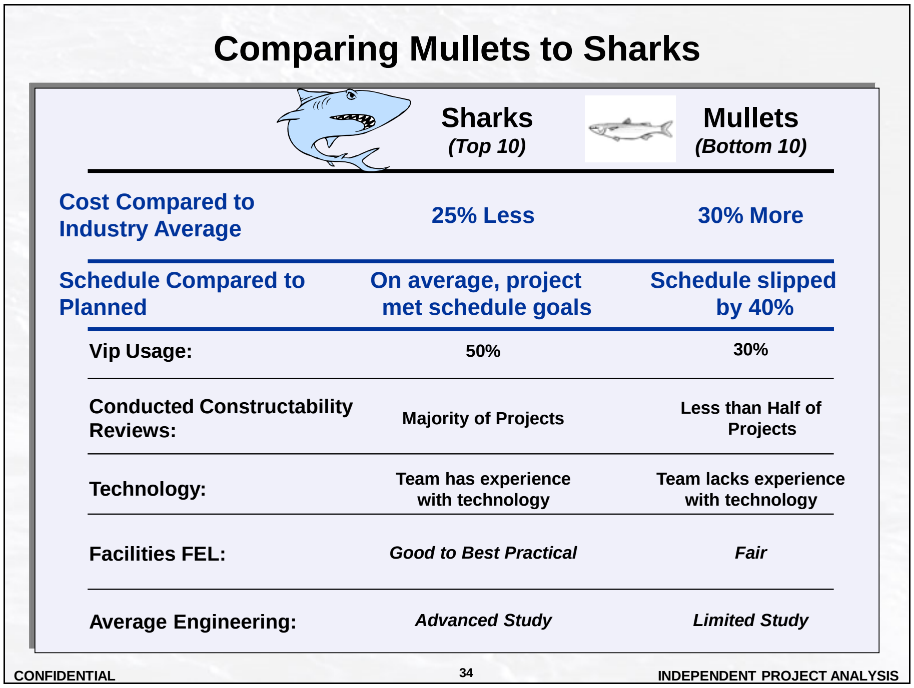


Figure 21

Figure 21 illustrates the difference between the best performing projects (Sharks) and worst performing projects (Mullets) by measure of cost performance. The ten best performing projects had more advanced levels of engineering definition.

SHARKS = Top Ten Cost Performances
MULLETS = Bottom Ten Cost Performances



Comparing Mullets to Sharks

	Sharks *(Top 10)*	Mullets *(Bottom 10)*
Cost Compared to Industry Average	25% Less	30% More
Schedule Compared to Planned	On average, project met schedule goals	Schedule slipped by 40%
Vip Usage:	50%	30%
Conducted Constructability Reviews:	Majority of Projects	Less than Half of Projects
Technology:	Team has experience with technology	Team lacks experience with technology
Facilities FEL:	*Good to Best Practical*	*Fair*
Average Engineering:	*Advanced Study*	*Limited Study*

CONFIDENTIAL 34 INDEPENDENT PROJECT ANALYSIS

Figure 22

Figure 22 sums up which practices were employed on projects referred to as Sharks versus those that were referred to as Mullets. On average the best projects had better levels of engineering definition, better overall FEL, experience with the technology and employed best practices such as constructability reviews and VIPs.

The following conclusions were drawn from the research study;

- Integrated subsea projects outcomes are more volatile.
- Better engineering definition improves cost and schedule performance.
- Facilities FEL improves facilities schedule predictability.
- The best subsea projects tend to have teams more familiar with the technology implementing project practices used by other successful projects.
- Be aware of industry trends.
    - Cost Improvement
    - Deeper Water
    - Technological Innovation
- Use best practices for volatility reduction and improved competitiveness.