FINAL

A CLOSEOUT EVALUATION OF THE ANGSI-D DEVELOPMENT PROJECT

Prepared for
Petronas Carigali

September 2009

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File No. PET-0906-CLO

PREFACE

This evaluation of the Angsi-D Development Project compares the project's performance with that of similar projects in Industry and with Petronas' average performance. As the project facilities scope is complete, we also compare the project facilities' actual performance with the estimates provided at sanction. To supply industry benchmarks, we used IPA's Upstream Project Evaluation System (PES®)[1] models. Based on this analysis, research, and input from the project team, we also provide lessons learned that can be used to improve future project performance in Petronas. This report establishes the final benchmarks for the Angsi-D Development Project facilities. The drilling has not been completed, and the actual metrics are based on the forecasted estimate of the campaign. IPA did not conduct a prospective (pre-sanction) evaluation of this project, and the assessment of the project drivers was based on the team's assessment of the level of preparedness in November 2007, when the Angsi-D Development Project was sanctioned.

The UPES database contains information on more than 1,000 projects conducted by more than 35 companies over the past 25 years. From this large database, we selected projects that are comparable to the Angsi-D Development Project. Using these comparison databases, we present benchmarks that reflect the performance of industry of today. We also used Upstream Cost Engineering Committee (UCEC[2]) data to further our analysis of the project and to provide additional clarity to the project's performance.

We measured the project's performance in the following areas:

- *Project Drivers* – Practices employed in the project definition phase that drove the project's performance.
- *Project Execution Discipline* – Practices employed in the project execution phase that drove project performance.
- *Project Outcomes* – Measures of project performance that resulted from the project's drivers and execution discipline.

In addition to presenting project benchmarks, this report summarises Lessons Learned. The most critical lessons are discussed in detail in this report.

Members of the project team supplied the information for this analysis in meetings held on 25 May – 26 May 2009, in the project offices in Kuala Lumpur, Malaysia. Project team members present at these meetings included Ismail B Ab Fatah (Project Manager), Dipak Mandal (Lead Reservoir), Samson Anthony (Geoscientist), Heru Hermawan (Drilling Superintendent), Seyri Anuwa (Drilling Engineer), Khairul Amiv (Drilling Engineer), Anas Ab Malek (Completion Engineer), Mohd Khairulsyah (Drilling Engineer), Norliza Salihin (Pipeline Engineer), Djohan Arifin (Senior Instrument and Control Engineer), Mohd Suzli (Mechanical and Piping Engineer), Suraiya Halim (Project Controller), Idras Ahmad (Facilities Manager), and Andrew Yeon Yi-Ren (Electrical Engineer).

Trung Ghi and Edith Jimenez represented IPA. Although members of the project team provided information, the interpretation and analysis are IPA's and do not necessarily reflect the

[1] PES is a registered trademark of IPA.
[2] IPA conducts the UCEC Metrics Program, which is the basis of the cost ratio analysis presented in this report. The purpose of the program is to provide members of the UCEC with metrics to support development of conceptual estimates, support reviews of contractor estimates, assess company metrics against industry norms, improve internal company tools and databases, and improve asset evaluation and concept development.

views of those interviewed. For more information, contact Trung Ghi of IPA Australia at +61-3-9458-7315 or tghi@ipaglobal.com or Edith Jiménez of IPA Australia at +61 (03) 9548-7324 or ejimenez@ipaglobal.com.

EXECUTIVE SUMMARY

This report evaluates the performance of the Angsi-D Development Project, which was executed in Malaysia. Petronas Carigali Sdn. Bhd. (PCSB) and Exxon-Mobil Exploration & Production Malaysia Inc. (EMEPMI) are the joint venture (JV) partners with equal shares in the Angsi field. The Angsi field is being operated by PCSB under the main terms and conditions of the gas production sharing contract (GPSC) signed in November 1998. The completed project facilities will be operated by PCSB, except for the host tie-ins at Guntong-D (GuD), Irong Barat-A (IBA), Seligi-A (SeA), and the Onshore Slugcatcher (OSC), which will be operated by EMEPMI. The Angsi field is located approximately 165 km off the east coast of Peninsular Malaysia in a water depth of 69 m. The Angsi Development has completed three phases (Phase I, II, and III) since the 1990s. Phase IV is the current phased development for the Angsi field and it includes the Angsi-D Satellite drilling platform (AnDP-D), the associated pipelines, and the host tie-in to the Angsi-A complex.

The Angsi-D Project's objective was to develop oil and gas reserves in the southwest area of the field with monetization of 64 million barrels of oil equivalent (MMBOE). The development will provide incremental oil of 15 to 20 thousand stock tank barrels per day (kstbd) to existing production. The amount of recoverable gas is 128.6 Bcf, which is included in the reserves. The above recoverable volume will be depleted with 11 development wells and with 5 optional wells. The plan was to drill 10 oil producer wells, 3 gas injector wells, and 3 water injector wells.

Angsi-D was developed as a satellite unmanned platform, and it was connected with three intrafield pipelines and controlled remotely from the AnPG-A platform. The first oil date was initially targeted for December 2008; however, this was not achieved until May 2009 because of the delay in awarding the platform contract and rig availability. The total estimated capital cost of the Angsi-D Development Project at sanction (23 November 2007) was RM1,267 million, including RM470 million for the AnDP-D drilling platform, RM334 million for three intrafield pipelines, and RM464 million for the drilling program. At project completion, the facilities (platform and intrafield pipelines) cost had decreased by 16 percent from the sanctioned cost estimate. The substantial decrease in cost was mainly due to the negotiated contract price of the Procure, Construct, and Commission (PCC) contract for the facilities scope after sanction. The drilling campaign has not yet been completed; however, the project team has forecasted that the drilling cost will not significantly deviate from the sanction estimate even after changes are made to the wells design.

BENCHMARKS

The Angsi-D Development Project's cost was not competitive compared with industry benchmarks, while the facilities' schedule performance was more competitive than industry. The tables in this section summarise the results of our analysis and present the Angsi-D Development Project metrics, industry averages, and Petronas averages for each key metric.

Project Outcome Metrics

Table 1 and Table 2 present the principal outcome metrics for the Angsi-D Development Project. We assess both the estimated and actual outcomes versus Industry, as well as the cost and schedule predictability of the sanction estimates. Safety metrics are based on downstream data and are provided as a reference point only.

Table 1
Summary of Safety and Cost Outcome Metrics for the Angsi-D Development Project

Outcome Metric	Angsi-D Development Project		Industry Average	Top Quartile/ Range
	Estimated at Sanction	Actual		
Safety (per 200,000)				
Recordable Incident Rate	Not App.	0.56	1.03[3]	Not Avail.
DART Rate[4]	Not App.	0.00	0.37[3]	Not Avail.
RM/BOE Metrics (Money of the Day) (Level 1)				
Asset Development Cost Regional RM/BOE[5] (Index)	14.65 (0.85)	Not Avail. [6]	17.25 (1.00)	Not App.
Non-Export Facilities Regional RM/BOE[7] (Index)	7.37 (0.65)	9.73 (0.86)	11.27 (1.00)	4.04 – 26.10
Wells RM/BOE[8] (Index)	7.28 (1.07)	Not Avail. [6]	6.80 (1.00)	2.35 – 12.13
Asset Development Cost Global RM/BOE[6] (Index)	14.65 (0.75)	Not Avail. [6]	19.52 (1.00)	Not App.
Non-Export Facilities Global RM/BOE[7] (Index)	7.37 (0.58)	9.73 (0.0.76)	12.72 (1.00)	4.02 – 25.94
Wells RM/BOE[8] (Index)	7.28 (1.07)	Not Avail. [6]	6.80 (1.00)	2.35 – 12.13
Concept Cost Effectiveness (Level 2) – RM Million				
Wells (Cost Index)	464 (1.03)	Not Avail [6]	449 (1.00)	307 (0.68)
Recovery per Well (MMBOE/well)	6	4[9]	11[10]	7 – 16
Component Cost Effectiveness (Level 3) – RM Million				
Total Facilities Regional (Weighted Cost Index)	804 (2.14)	674 (1.79)	376 (1.00)	Not Avail.
– **AnDP-D Regional (Cost Index)[11]**	470 (1.58)	406 (1.36)	299 (1.00)	Not Avail.
– **Pipeline Regional (Cost Index)**	334 (4.34)	264 (3.43)	77 (1.00)	55 (0.74)
Total Facilities Global (Weighted Cost Index)	804 (1.59)	670 (1.33)	505 (1.00)	Not Avail.
– **AnDP-D Global (Cost Index)[11]**	470 (1.33)	406 (1.15)	352 (1.00)	Not Avail.
– **Pipeline Global (Cost Index)**	334 (2.18)	264 (1.73)	153 (1.00)	112 (0.76)
Wells (Cost Index)	464 (0.62)	Not Avail. [6]	745 (1.00)	562 (0.75)
Deviation				
Asset	Not App.	Not Avail. [6]	7 percent	Not App.
Facilities	Not App.	-16 percent	12 percent	Not App.
Wells	Not App.	Not Avail. [6]	13 percent	Not App.

[3] Industry metrics from IBC 2008
[4] DART: A work-related injury or illness resulting in days away from work, restricted duties, or job transfer.
[5] Excludes export and onshore costs. Asset $/BOE is additive of the facilities $/BOE and the wells $/BOE.
[6] The wells program has not been completed. The team estimates that drilling will be completed in May 2010.
[7] Non-Export Facilities $/BOE is based on estimated life-of-project production stream (Facilities' base design).
[8] Wells $/BOE is based on the "actual" life-of-project production stream, or the estimate that is updated at the start of production. In this case, the estimated life-of-project production stream was used.
[9] As of May 2009.
[10] Average is based on 32 oil projects in water depth <100 meters and > 20 meters.
[11] Benchmark is based on UCEC data.

At the component level, the capital cost for the project's intrafield pipelines was substantially higher than Industry. The result was driven by high installation and transportation costs. The project team's base plan was to complete the installation of the intrafield pipelines in one campaign; however, the installation vessel promised to the Angsi-D Development Project team was given to other higher-priority projects within the PCSB portfolio. The installation campaign was completed over two sessions. The installation vessels and contracts were managed (which includes scheduling of all installation vessels) by the Department of Installation (DFIN[12]) within PCSB, and the project team had little control over the type of vessels and contract rates.

The AnDP-D platform cost was benchmarked using Upstream Cost Engineering Committee (UCEC[13]) metrics because the AnDP-D platform can support a tender assisted drilling (TAD) rig, which is not part of the wellhead platform (WHP) cost model. As a result, the platform cost index should be interpreted with caution, because it does not take into account variables such as water depth, maximum wave height, hydrocarbon throughput, and number of slots. The analysis shows that the AnDP-D platform cost is more expensive than other projects in Asia (and global projects) of similar jacket and topside weight. If the topside dry weight and water depth are considered, the jacket weight is more than 27 percent heavier than a typical similar project executed in Asia and more than 16 percent heavier than projects executed globally. These results support IPA's conclusion that the Angsi-D platform was installed at a premium compared with Petronas' competitors in the upstream industry.

Conversely, compared to similar projects, the Angsi-D Development Project's wells estimated cost of RM464 million was competitive. The concept for this field and reservoir complexity is industry average as indicated by the cost index of 1.03. If the team's prediction that drilling costs will not deviate from the estimate holds true, the drilling team will maintain its drilling competitiveness (Wells Component Cost Index of 0.62).

Finally, the Angsi-D Development Project experienced a cost decrease of 16 percent for the facilities scope. The cost deviation was predominantly driven by the team's ability to negotiate a lower contract price post project sanction.

[12] DFIN manages all installation vessel contracts in PCSB. It is DFIN's responsibility to schedule installation vessels for the project team once the project team has indicated the installation specifications and installation dates. The intent of having a centrally controlled installation department is to achieve economies of scale through contracting large fleets of installation and support vessels.

[13] The UCEC Metrics Program is the basis of the cost ratio analysis presented in this report. The purpose of the program is to provide members of the UCEC with metrics to support development of conceptual estimates, support reviews of contractor estimates, assess company metrics against industry norms, improve internal company tools and databases, and improve asset evaluation and concept development.

Table 2
Summary of Schedule Outcome Metrics for the Angsi-D Development Project

Outcome Metric	Angsi-D Development Project		Industry Average	Top Quartile
	Planned at Sanction	Actual		
Effectiveness				
Facilities Execution Duration (Schedule Index)	27 months (1.17)	24 months[14] (1.05)	23 months (1.00)	20 months (0.86)
Well Construction Duration (Schedule Index)	485 days (0.88)	Not Avail. [15]	553 days (1.00)	426 days (0.77)
Cycle Time Duration	29 months (1.25)	25 months[14] (1.10)	23 months (1.00)	Not Avail.
Deviation				
Facilities Execution Schedule	Not App.	-12 percent[14]	19 percent	Not Avail.

As shown in Table 2, the facilities execution of 24 months was slightly slower than Industry, and the project underran its planned execution schedule by 12 percent. The Angsi-D Development Project was slightly more predictable than for similar projects in the industry, which tend to overrun their planned schedules by 19 percent. The planned schedule was considered aggressive by the team, but was moderately conservative compared to Industry.

The actual execution schedule duration, start of detailed engineering to first oil, was 32 months. Approximately 8 months was removed or normalised from the actual execution duration because the project was put on hold until legal issues with the fabrication contractor were resolved. Therefore, the adjusted actual execution duration, as shown in Table 2, is 24 months. The Angsi-D Development Project team was asked to fast track the project schedule to meet management's first oil request. The project team reduced the definition and engineering phases to 3 months each by using the same WHP design as that of the Angsi-B platform. Moreover, the project team engaged detailed design before project sanction to allow adequate time for procurement and fabrication. Pre-sanction detailed design deviated from the PCSB project delivery process but was approved by management. To meet the first oil date the project team awarded the pipeline fabrication and long-lead equipment contracts prior to project sanction (which also deviated from the PCSB project delivery process). However, because the rig could not be secured as planned, the fast tracking was eroded yielding an industry average schedule result.

The planned wells construction duration of 485 days is aggressive relative to Industry. At the time of the interview, the team had completed the first development well and had started drilling the second well. The wells program is estimated to be completed by April 2010, which would be a 44 percent schedule slip.

The targeted first oil date of December 2008 was not achieved because the project team could not secure a drilling rig. First oil was not achieved until the end of May 2009, which was 5 months late compared to the planned schedule.

[14] The Facilities Schedule has been adjusted 8.8 months for time for RFSB to resolve legal issues with Carigali-PTTEP Operating Company (CPOC). PTTEP is a Thailand national petroleum exploration and production company.
[15] The Wells program is estimated to be completed by May 2010.

Table 3
Summary of Life-of-Project Production Stream (Resource Promise) and Operability Metrics for the Angsi-D Development Project

Outcome Metric	Angsi-D Development Project		Industry Average	PCSB Average
	Estimated at Sanction	Change at First Production		
Change in Life-of-Project Production Stream Attributed from Sanction to First Production	63.7 MMBOE	Not Avail.	-10 percent	-7 percent
Production Attainment in Months 7-12[16]	Not Avail.	Not Avail.	82 percent	91 percent

Table 3 shows the estimated resource promise at sanction compared with the change in the estimate at first production and production attainment. The sanctioned resource promise is 63.7 MMBOE. However, it was downgraded by approximately 34 percent to 41.8 MMBOE after the subsurface optimised the depletion plan prior to the drilling campaign. At the time of the interview, first oil was not achieved and therefore the change in life-of-project production stream metric at first production is not reported.

[16] Production attainment data were not available at the time of the interview; they will be collected 12 months after start up.

Asset Development Practices and Project Drivers

IPA has developed a suite of metrics that evaluate the project's practices and drivers at sanction. Table 4 presents the metrics for the Angsi-D Development Project's drivers and asset development practices.

Table 4
Summary of Project Practices and Drivers for the Angsi-D Development Project (at Sanction)

Driver or Practice	Angsi-D Dev. Project	Industry Average	PCSB Average	Best Practical at Sanction
Appraisal Strategy	Aggressive	Aggressive 23 percent of projects	Moderate 17 percent of projects	Not App.
Reservoir Complexity **I-27/35** **I-15** **I-70/100**	35 32 40	39 Range:19 to 57	37 Range:19 to 57	Not App.
Wells Complexity	54	52 Range:17 to 109	49 Range:19 to 109	Not App.
FEL Index – Asset	6.46 *(Fair)*	6.55 (*Fair)*	8.08 *(Screening)*	4.00 to 5.50
Reservoir	6.08	6.00	6.86	4.50 to 5.50
Wells	6.26	6.67	7.13	5.00 to 6.00
Facilities (Platform)	6.95 *(Fair)*	7.31 *(Fair)*	9.11 *(Screening)*	3.75 to 4.75
Pipeline	6.33 *(Fair)*	6.10 *(Fair)*	7.80 *(Screening)*	4.25 to 4.75
Team Integration	Integrated	50 percent	57 percent	Yes
Integration of Operations With Project Team	Integrated	65 percent	71 percent	Yes
Technical Innovation of Facilities	Routine	63 percent	80 percent	Not App.
Team Experience With Facilities Technology	Routine	57 percent	80 percent	Not App.
Technical Innovation of Wells	Routine	43 percent	50 percent	Not App.
Team Experience With Wells Technology	Routine	46 percent	50 percent	Not App.
Facilities VIPs Used	11 percent	27 percent	9 percent	40 to 60 percent
Subsurface VIPs Used	17 percent	35 percent	19 percent	Not App.

The appraisal philosophy for Angsi-D was *Aggressive.* The Angsi-D field was appraised with one well, and the remaining data were provided from previous drilling campaigns (data from over 100 wells) close to the Angsi-D field. However, the highly stacked and compartmentalized reservoir features in the Angsi-D field prohibited an accurate correlation with the nearby wells data. Based on the available subsurface data, the subsurface team achieved an industry average Reservoir Front-End Loading (FEL) Index. The Facilities FEL also matched Industry average, and the weakest area in definition was project execution planning (PEP). Pipeline FEL was also *Fair*, similar to the industry average but less defined than *Best Practical* at sanction. Wells FEL was better than industry average at sanction, driven by the routine well designs.

The Angsi-D Development Project scope was relatively conventional. PCSB has ample experience in the region installing WHPs and pipelines. The platform design was based on the Angsi-B platform, which enabled the Angsi-D Development Project team to work around the lack of experienced staff and perceived schedule pressures.

The wells design was also relatively routine within PCSB. The technology employed is industry-proven, but was new and potentially challenging to the team members. The subsurface and drilling team conducted various technical peer reviews during the life of the project.

The facilities team used 11 percent of the Asset and Facilities VIPs applicable to the Angsi-D Development Project, which is below the industry average of 27 percent of VIPs use. Nine VIPs were applicable to the Angsi-D Development Project, and the team used only 3D CAD during FEED and detailed engineering. The subsurface team applied one out of six relevant Subsurface VIPs (SSVIPs), or 17 percent. The team used 3D visualization to analyse the reservoir.

Project Execution Discipline

IPA evaluates *Execution Discipline,* which comprises several key factors that play a role in the successful execution of E&P projects. IPA evaluates project control as measured by the Project Control Index (PCI); the incidence of key team member turnover; and the frequency and impact of major late changes. Table 5 summarises the project execution discipline for the Angsi-D Development Project.

Table 5
Summary of the Angsi-D Development Project's Execution Discipline

Project Execution Discipline	Angsi-D Dev. Project	Industry Average	PCSB Average	Best Practice
Project Control Index (PCI)	*Deficient*	*Poor*	*Poor*	*Good*
Project Manager Turnover	No	62 percent of projects	86 percent of projects	No Turnover
Major Late Changes	Yes	64 percent of projects	100 percent of projects	0.

The Angsi-D Development Project's PCI rating was *Deficient*, which is lower than the Industry and PCSB averages of *Poor*. The lack of a project controls specialist and estimate validation process contributed to the poor rating. The project experienced major late changes. Ongoing optimisation studies after sanction caused scope and design changes to the wells campaign, which affected the drilling campaign's cost and schedule. Integral to the project was the experience and continuity of the project manager through project definition and execution. Unlike most PCSB projects, project manager turnover was not an issue for the Angsi-D Development Project. However, the project faced numerous turnovers in key staff positions throughout execution.

CONCLUSIONS

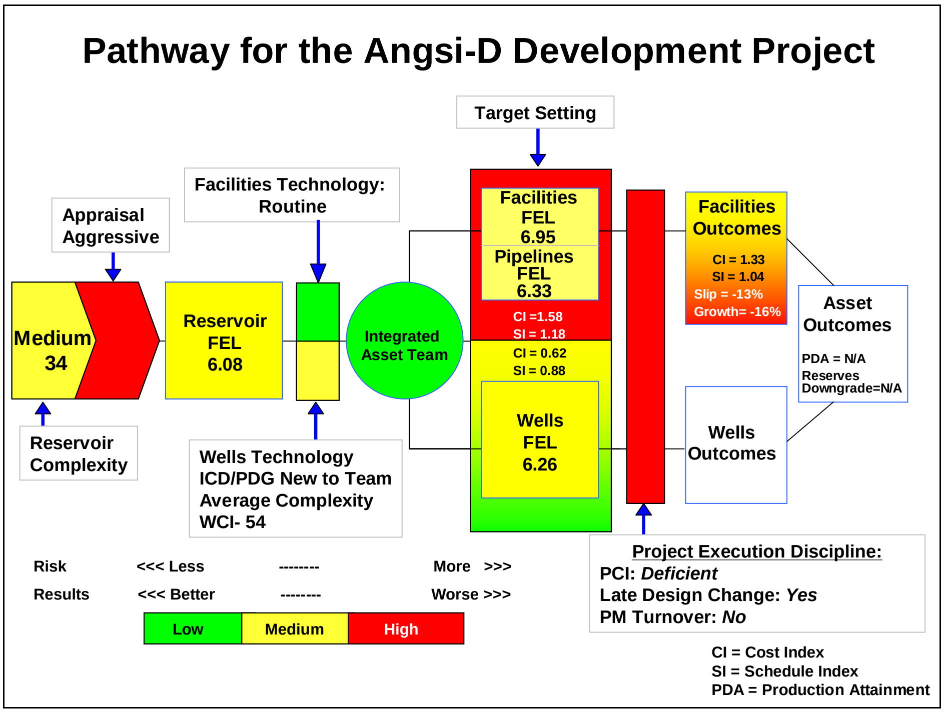

Figure 1

IPA assessed the Angsi-D Development Project drivers and the preparation achieved by the project team at sanction. The drivers are related to the project outcomes through the Pathway to Success, shown in Figure 1. The Angsi-D Development is a field with a fast-tracked schedule mandated by management. The project team faced four challenges in execution: schedule pressure to achieve first oil, lack of basic data from the aggressive appraisal strategy, high attrition rate of team members, and the lack of a project control specialist on the project team.

The facilities scope achieved industry average definition at sanction. The designs were standardised from a previous Angsi project to minimise risks from the schedule pressures and the inexperienced project team. The facilities cost was more expensive than industry average based on weight and water depth. The project had a normalised cost underrun, which was realised through negotiations with contractors post board approval of the estimate.

The execution duration was industry average but faster than the target duration. Because the project team was unable to secure a rig in time, first oil was late by 5 months, which eroded fast track efforts. Despite the routine facilities technology, adopting a similar platform design from previous phases, and performing detailed engineering prior to project sanction, the project team's cost and schedule estimate was too conservative resulting in an expensive facility. The poor facilities outcomes are also attributed to the lack of control over the installation vessels and rig.

LESSONS LEARNED

Based on our analysis of historical industry performance and our assessment of the Angsi-D Development Project, we present the following key lessons for future projects.

1. *Using previous Angsi design helped schedule performance*. The AnDP-D platform was based on the Angsi-B WHP design. The team modified the existing design to suit the seabed strength and drilling rig requirements. This approach was much faster than starting the AnDP-D design from scratch, and was especially helpful given the project's time constraints.

2. *Completing subsurface studies before engineering definition reduces late changes.* The Angsi-D Development Project began engineering before key subsurface study results were available to support and finalise the well construction scope. The project team suffered from several well design changes as a result. Historically, projects that obtained all basic data before entering the Define phase achieved their business objectives more often than did projects that lacked timely basic data. Providing basic subsurface data early improves operability and production attainment.

3. *Continuity in key discipline positions helps achieve predictable project outcomes*. The Angsi-D Development Project suffered a high number of key team member turnovers. Project team turnovers are detrimental to the execution schedule and erode predictability of project outcomes. Turnover of key team members should be avoided. If turnover is unavoidable, Petronas should give proper attention to retention, succession, and transition plans to ensure an adequate and timely handover of project activities and responsibilities, including the communication of issues that have already been resolved.

4. *Good project execution planning is key to project success.* The project execution plan (PEP) is a key document in any project and serves as the basis for the project team to effectively progress into each phase. Although the Angsi-D Development Project was not complicated in terms of technology, it was schedule and resource constrained. The weak PEP, led by a weak schedule, hindered the project team's efforts to respond to the constraints.

5. *Estimate validation helps to achieve cost competitiveness.* The project controls for the Angsi-D Development Project were *Deficient*. The lack of estimate validation contributed to the high costs compared with Industry for similar WHP and pipelines. The facilities scope underran, and the cost estimates could have been significantly more accurate if they had been validated by an in-house estimating group. Given the lack of team control in the installation vessel and rig rates, project teams for upcoming projects should be vigilant in comparing recently completed projects to ensure the vessel and rig rates are in line with industry averages.

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INTRODUCTION

OBJECTIVES

The business objective for the Angsi-D Development Project was to develop oil and gas reserves in the southwest area of the field with monetization of 35 million stock tank barrels (MMstb) of oil, 4.4 MMstb of condensate (or 39 MMstb total liquids), 82 billion standard cubic feet (Bscf) of non-associated gas, and 62 Bscf of associated gas (or 144 Bscf total gases). Petronas Carigali Sdn Bhd's (PCSB) business driver was to achieve first oil production in the fourth quarter of 2007. This first-oil target was then changed and confirmed for 11 December 2008 at project sanction. The development seeks to provide incremental 15 to 20 kstb oil to existing production.

The Angsi-D Development Project's objective was to develop the Angsi-D field with a four-legged drilling platform (AnDP-D) and drill 11 development wells to recover oil and gas from the Angsi-D field. The plan was to send the full well stream (FWS) to the AnDR-A platform, about 11 km away.

First oil was reached on 31 May 2009 with an approximate 16 percent cost underrun. The cost estimate at sanction was RM1,267 million. The wells program is ongoing, has slipped from the planned schedule, and the last well is expected to be complete by 9 April 2010.

FIELD DESCRIPTION

The Angsi field has five areas: Main, West, North, South, and Southwest. The areal distribution of the hydrocarbon-bearing reservoirs is the basis for these areas. The Angsi-D field is located in the Southwest area, and its reserves are from the Group I sands. The major oil contributors are I-27 and I-35U with additional production from I-15L, I-100, and I-72. The hydrocarbon accumulation is composed of fluvial clastics of the Miocene.

I-27/35U contains 64 percent of the reserves-in-place and I-15 covers 23 percent. The I-27/35U sands are in communication forming a single reservoir that shares the same fluid contacts and fluid gradient. The porosity is 15 to 30 percent pore volume, and the gas-oil contact ranges between 1,640 to 1,646 m true vertical depth subsea (tvdss) with a gas cap and oil leg. The pressure in the reservoir is lower than the bubble point, which dictated the need for gas and water injection. The reservoir has minimal faulting. I-15 has the largest accumulation with a gas cap and oil leg present. The reservoir is approximately 1 m to 4 m thick with excellent permeability.

Table 6 provides the most likely scenario of recoverable reserves for every reservoir in the Angsi-D field.

Table 6
Recoverable Volume Estimate

Recoverable Volume	Most Likely
Oil (MMstb)	
I-27/35	22.9
I-15 East Area	2.6
I-15 North Area	3.8
I-100/70/15W	5.2
Condensate	4.4
Total Recoverable Oil	**38.9**
Gas (MMBOE)	
I-70/75/85/95	8.8
I-100	4.1
I-27 Area F	1.3
Associate Gas	10.6
Total Recoverable Gas	**24.8**
Total Field MMBOE	**63.7**

PROJECT SCOPE

The Angsi-D Development Project scope includes the following:

- A four-legged unmanned satellite drilling platform (AnDP-D) with 16 conductors. The platform has a power generation system with a micro turbine generator to supply all the electrical power on the platform. The AnDP-D is designed to support a tender assisted drilling (TAD) rig.
- Three new intrafield pipelines to connect the AnDP-D to the Angsi-A complex.
  - 12 inch x 11 km carbon steel pipeline multiphase electric resistant welding to transport the hydrocarbon from AnDP-D to AnDR-A
  - 6 inch x 9.8 km CS pipeline to transport gas lift from AnDR-A to AnDP-D
  - 10 inch x 11 km CS pipeline to transport water injection from AnDR-A to AnDP-D
- The drilling program at sanction was to drill 11 (8 producer and 3 injectors) development wells plus 5 optional wells if additional recoverable volumes were found. Fourteen wells will be drilled with a trajectory of “build and hold,” and the remaining two wells will have a horizontal profile.

PROJECT HISTORY

Angsi-D is the fourth phase of an overall Angsi Field development. The Angsi-D Development Project was included in the latest revision (Rev 3, submitted in 2005) of the FDP, which was used to develop Phase 1, 2, and 3.

Field Discovery and Appraisal

Between 1999 to March 2004, the Angsi FDP was revised to accommodate the development of Phase 1, 2, and 3. These phases developed the majority of the Angsi field recovering more than 350 MMBOE. To date, the Angsi field has installed four platforms and associated pipelines. The Angsi-A complex (developed during FDP Rev1) is the gas hub to secure supply to Peninsular Malaysia.

The Angsi-D Development is defined by FDP Revision 3, which was submitted to PMU in July 2005 and approved in March 2006. Revision 3 included additional information provided from the first appraisal well, Angsi-8, drilled in August 2004 in the Southwest area of the Angsi field. Angsi-8's main objectives were to appraise the fluid content, structure, stratigraphy, and core, and to obtain MDT data from the I-27/35U sands. During this appraisal study, the Angsi-8 well discovered the I-72 oil reservoir and updated the I-35 Extension Development and I-25 Channel. The FDP Revision 3 developed hydrocarbon reserves in the Southwest area of the field.

The FDP Revision 3 set the basis for conceptual engineering, the design basis memorandum, and the detailed design elements for the satellite platform AnDP-D and AnPG-A Complex Facility Upgrade.

Select and Define Phase

After the FDP Revision 3 was approved by PMU, the project team, driven by the first-oil target, obtained approval from CMC for initial funding to cover project management, pre-engineering, and detailed design costs. The funds were endorsed in November 2005. PCSB approved the overall contracting strategy in June 2006. MMC was awarded conceptual and detailed design.

In September 2006, detailed engineering started, and the Project Integrated Review #2 was done for the conceptual and detailed design in December 2006. MMC approved the P&IDs for construction in December 2006. At that time, the project team forecasted first oil in the fourth quarter of 2007.

In September 2006, Petronas approved the tender plan for the jacket and topside. The project team began the contracting process and submitted the recommendation to Petronas Carigali Sdn. Bhd. (PCSB) in December 2006. Ramunia Fabricator Sdn. Bhd. (RFSB) was the recommended contractor for fabrication. CMC approved the recommendation in February 2007.

From March to November 2007, the contract award was put on hold by CMC because of legal issues between RFSB and Carigali-PTTEP[17] Operating Company (CPOC). Project sanction was therefore delayed, and awarding of the contracts had to wait until 8 months later when the legal issues between the contractors and suppliers were resolved. The majority of the project team worked on the Sotong Project in the interim.

During the legal negotiations, JP Kenny worked on the pipeline designs and Mitco Japan procured the pipeline material.

Execution Activities Pre-Sanction

During September 2007, the team pre-laid the 6-inch and 12-inch pipelines. The plan was to install all three pipelines in one campaign before the monsoon season began in November 2007; however, the installation vessel was mobilised to another project. The 10-inch pipeline was preserved for 1 year before it could be installed.

In October 2007, the project team reviewed the project schedule, and as a consequence of the legal delay the first oil target was reset to December 2008.

Project Sanction

[17] PTTEP is a national petroleum exploration and production company in Thailand.

The legal issues pertaining to RFSB were resolved due to Petronas' intervention, and PCSB approved the project in November 2007. The team awarded the platform (jacket and topside) fabrication soon afterwards.

The new first hydrocarbon date was confirmed for 11 December 2008, and the recoverable resource was 38.9 MMstb of oil and 143.8 Bcf of gas or a total of 63.7 MMBOE.

Within this period, the drilling lead, facilities lead, and project controller moved to another project because of professional development.

Project Execution

Jacket and topside fabrication was loaded out and piles/conductors were completed in October 2008, and were installed by November 2008 with minimal issues.

Hook-up and commissioning (HUC) commenced in November 2008 and was completed in May 2009. Offshore installation and hook-up occurred during the monsoon period from November 2008 to February 2009. During the HUC phase, the project faced resource issues, as RFSB had laid people off because of cash-flow problems.

The first hydrocarbon date was moved to May 2009 because the project team could not secure a rig to commence the drilling campaign.

In December 2008, the subsurface team revised the recoverable volume to 41.8 MMBOE based on optimisation of the depletion plan. The downgrade represents a 34 percent decrease from the estimated resource promise in the FDP Revision 3. Also, the designs of the wells had multiple changes during this time, which included modifying three wells to extended reach drilling profiles, changes to target depths, and completion arrangements (single to dual completions).

In January 2009, the TAD rig contract was signed with Tioman T10, which would commence drilling the first Angsi-D well in April 2009. The T10 rig completed its drilling campaign early for the previous project. The Angsi-D Development Project team secured the remaining drilling slot in September 2009 before the rig had to be mobilised for another drilling campaign. The negotiated rig rate was US$90,000 per day. The cost estimate at sanction assumed a day rate based on SeaRex-9 TAD of US$130,000 per day.

The project team is also considering a new TAD rig from Kecana. Fabrication of the new TAD rig is expected to be completed by November 2009.

On 15 May 2009, the first producer well was drilled. However, first oil could not flow because a blowout preventer valve was installed incorrectly on the WHP. On 31 May 2009, the team achieved first oil. The drilling campaign will continue until April 2010.

PROJECT MANAGEMENT ISSUES

Team Integration

IPA defines an *integrated team* as a team of full- or part-time representatives covering all key disciplines, identified prior to project sanction, and having specific responsibilities that are defined and understood by all team members with authority to make decisions. Research shows that having an integrated team results in better overall project performance. For example, projects with integrated teams require less contingency than projects without integrated teams.

The Angsi-D Development Project team was *Integrated*. The project had dedicated functional groups for the Angsi field development which resulted in faster flow of key data amongst the groups. The Operations group was involved from the beginning of the project. Roles and responsibilities were defined and understood by the Angsi team members.

Contracting Strategy

The Angsi-D Development Project’s overall contracting strategy was approved in June 2006. To accomplish the business objectives and project objectives, the team did the soil boring, site, and route surveys using PCSB’s existing umbrella contractors. MMC did the conceptual design, FEED, and detailed engineering for the WHP. MMC had a lump-sum contract with a unit rate for any change. JP Kenny was awarded the pipeline design under a lump-sum contract.

The Angsi-D Development Project adopted a Procure, Construct and Commission (PCC) lump-sum contracting strategy for the WHP scope, awarded to RFSB. Major items were procured through the Supply Chain Management department within PCSB. The long-lead equipment contract was awarded by competitive bidding to local suppliers licensed by Petronas.

A Vendor Development Program was initiated to improve the manufacturing capabilities in Malaysia and the project was required to use approved vendors in this program. The vendors were chosen based on an open bid tendering process, which screened first for technical capabilities and second for the lowest bid.

The team used an existing contract with Mitco Japan Sdn. Bhd. for structural steel and pipeline procurement. Pipeline coating was awarded to Bredero Shaw.

The Transportation and Installation contract was established under an existing umbrella arrangement with TL Offshore Sdn Bhd (TLO). The umbrella contract was managed under the Department of Installation (DFIN), which is a centrally operated division for all PCSB offshore installation projects. All projects that require a workboat, barge, or any floating vessels need to submit a request to the construction department to engage TLO. TLO was responsible for sourcing the vessels for the requested work schedule as agreed on during planning each year. The installation vessels for the WHP and pipelines for the Angsi-D Development Project were therefore contracted to TLO. The Sea Horizon and Enterprise 3 installation vessels were contracted to install the Angsi-D pipelines at a rate of RM163,248 per day in 2008. In 2009, the Enterprise 3 rate increased to RM185,736 per day.

BASIS OF COMPARISON

The analysis presented in this report is based on models and comparisons that draw on the IPA Upstream Database. Using the information from this database, IPA has created statistical models that relate project characteristics and project practices—particularly those practices used during the project definition phase—to evaluate a project's status.

Several inherent project characteristics influence performance. Factors such as project size, location, use of new technology, technical complexity, and percent of revamp affect outcomes such as cost, schedule, and production attainment to varying degrees. Based on these findings, we extract from the larger database a subset of projects to be the basis of comparison for the project being analysed.

We used a recent subset of upstream projects to establish industry benchmarks for the project drivers. Table 7 outlines the specific characteristics of this subset.

Table 7
Characteristics of Recent Subset of Upstream Projects

Characteristic	Angsi-D Development Project	Dataset (410 projects, at UIBC 2008)		
		Minimum	Median	Maximum
Year of Sanction	2007	2000	2004	2008
Region	Malaysia	North America, 16%; Europe, 22%; Africa, 12%, South America, 20%, SE Asia, 17%, Other, 13%		
Estimated Life-of-Project Production Stream (MMBOE)	64	2	88	>1,500
Actual Asset Cost (RM MM)	1,138[18]	<39	865	>16,500
Water Depth (m)	71	1.5	113	> 2,100

WELLS $/BOE DATASET

Table 8 shows the Wells $/BOE dataset, which was used to establish industry benchmarks. The Angsi-D Development Project is well within the range of characteristics for this dataset.

Table 8
Characteristics of the Wells $/BOE Dataset

Characteristic	Angsi-D Development Project	Dataset (297 projects)		
		Minimum	Median	Maximum
Region	Malaysia	North America, 29%; Europe, 36%; Africa, 8%; South America, 14%; Oceania, 5%; Asia, 8%		
Post Startup Life-of-Project Production Stream (MMBOE)	64[19]	2	76	732
Water Depth (m)	71	24	154	2,205

[18] The wells program is not complete and the cost is based on a forecasted drilling projection.
[19] After sanction, the recoverable reserves were optimised to 42 MMBOE.

FACILITIES $/BOE DATASET

Table 9 shows the Facilities $/BOE dataset, which was used to establish industry benchmarks. The Angsi-D Development Project is well within the range of characteristics for this dataset.

Table 9
Characteristics of the Facilities $/BOE Dataset (Includes Subsea)

Characteristic	Angsi-D Development Project	Dataset (157 projects)		
		Minimum	Median	Maximum
Region	Malaysia	GoM, 35%; Europe, 29%; Africa, 13%; Other, 23%		
Estimated Life-of-Project Production Stream(MMBOE)	64	2	64	> 1,000
Water Depth (m)	53	6	111	> 2,000

FACILITIES SCOPE DATASET

Platform Dataset

The Angsi-D Development Project facilities comprise a WHP and three intrafield pipelines. The facilities' costs were benchmarked using Upstream Cost Engineering Committee (UCEC[20]) metrics because the AnDP-D platform was designed to support a TAD, which is not considered in IPA's WHP cost model. The UCEC data do not account for variables such as water depth, maximum design wave height, conductor slots, and if the WHP is manned, and do not differentiate between a processing platform and a minimal processing platform.

[20] IPA conducts the UCEC Metrics Program, which is the basis of the cost ratio analysis presented in this report. The purpose of the program is to provide UCEC members with metrics to support development of conceptual estimates, support reviews of contractor estimates, assess company metrics against industry norms, improve internal company tools and databases, and improve asset evaluation and concept development.

Pipelines Scope

The Angsi-D Development Project's pipeline scope is well within the range of characteristics that comprise our standard pipeline model dataset. Given the similarity of the Angsi-D's pipelines scope to the parameters of IPA's model, the cost benchmarks presented in Table 10 are based on a regression analysis of this dataset.

Table 10
Characteristics of the Pipelines Dataset

Characteristic	Angsi-D Development Project	Dataset (65 projects)		
		Minimum	Median	Maximum
Year of Sanction	2007	1992	1998	2004
Region	Malaysia	GoM, 26%; Europe, 25%; Asia, 23%; Africa, 15%; South America, 9%; Middle East, 2%		
Actual Cost (RM million)	264	3	69	2,119
Pipeline Diameter (in)	12.0, 10.0, 6.0	5.6	11.7	45.8
Pipeline Length (km)	31	1	28.6	658
Water Depth (m)	68 (max)	11.4	90	1,935

WELL CONSTRUCTION DATABASE

Likewise, as shown in Table 11, the subsurface and drilling characteristics of the Angsi-D Development Project lie well within the range of our standard subsurface benchmarking datasets; therefore, we are readily able to benchmark these elements using our standard analyses.

Table 11
Characteristics of the Well Construction Dataset

Characteristic	Angsi-D Development Project	Dataset (161 projects)		
		Minimum	Median	Maximum
Year of Sanction	2007	1990	1997	2004
Estimate Cost (US$ million)	464	2.3	84	1,590
Region	Malaysia	North America, 30%; Europe, 36%; Africa, 11%; South America, 11%; Oceania, 5%; Asia, 7%		
Water Depth (m)	71	6	140	2,205
Estimated Life-of-Project Production Stream (MMBOE)	64	2	67	3,287

PROJECT OUTCOMES

In the following sections, we summarise the estimated and actual outcomes for the Angsi-D Development Project's cost, schedule, and production stream. Industry benchmarks are presented for comparison. We evaluate several measures of performance to ensure that one area is not compromised to achieve results in another area. An excellent project can accomplish its goals without compromising the quality of work in one or more areas.

COST

The highest level cost benchmark is based on *capital cost per barrel* for facilities and drilling. The benchmark provides an overview of the project and gives an indication of the relative cost performance of the project without a detailed review of all mitigating factors. The capital cost per barrel model compares the project with the industry average capital expenditure per barrel of oil equivalent ($/BOE). The next level of detail examines the wells concept (i.e., the Well Construction Concept Cost Analysis asks what Industry would pay to develop this life-of-project production stream, regardless of concept chosen). Finally, on a more detailed level, we benchmark the cost of individual project components, such as platforms and pipelines. Therefore, to draw any conclusions based on the cost benchmarks, we need to understand how the various levels of cost metrics relate to one another. For example, schedule is a major driving factor for the wells component cost. In turn, the wells component cost drives the competitiveness of the wells concept. The wells concept cost drives the wells development cost (or $/BOE). IPA also records cost and schedule predictability and compares them to historical averages. The analysis of competitiveness and the predictability of a project give teams and companies a complete understanding of a project's capital performance.

Table 12 summarises the estimated and actual costs for the Angsi-D Development Project using the project team's cost breakdown. The estimate for the platform was RM470 million and the estimate for the pipeline was RM334 million, including RM42 and RM30 million in contingency, respectively. The wells campaign was estimated at RM464 million. The total funding available for this project was RM1,267 million. The final cost was RM406 million for the platform scope and RM264 million for the pipeline. The forecasted cost for the wells campaign is RM464 million. A total cost of RM1,134 million is anticipated at the completion of the drilling campaign.

Table 12
Cost Distribution for the Angsi-D Development Project (RM MM)[21]

Cost Category	Total Project Estimated Cost at Sanction		Total Project Actual Cost	
Facilities and Export				
	Platform	**Pipeline**	**Platform**	**Pipeline**
Front-End Engineering	1.7	0.8	1.7	0.8
Detailed Engineering	10.2	4.8	9.6	0.9
Project Management	40.0	4.4	44.0	4.9
Fabrication/Material/Equipment	216.4	57.0	209.8	56.8
Tow, Integration, Transport, Installation	130.9	233.4	115.9	197.8
Hook-up and Commissioning	27.9	2.9	25.5	2.7
Other Project Costs	0.0	0.0	0.0	0.0
Contingency	42.6	30.3		
Total Facilities Costs	**469.7**	**333.6**	**406.5**	**263.8**
Well Construction				
Detailed Well Planning	Costs embedded below		Drilling campaign not yet completed	
Non-Well Activities	9.1			
Xmas Tree	3.5			
Drilling	279.2			
Formation Evaluation	22.1			
Completion	107.0			
Other Project Costs	0.7			
Contingency	42.2			
Total Well Program Costs	**463.8**		**463.8**[22]	
Total Facilities and Well Program Costs	**1,267.1**		**1,134.1**[24]	

[21] Total costs may not add up due to rounding.
[22] The wells program is not complete and the cost is based on a forecast.

Benchmark Normalisation

IPA cost adjustment encompasses currency exchanges and time/inflation changes. All projects are converted to U.S. dollars. Costs are then (de)escalated to January 2003, which is the current base period for upstream models and analysis. IPA uses a variety of indices to calculate the inflation, such as steel prices, equipment prices, oil price, labour rates, material costs, rig rates, etc. These indices are updated monthly. A plot of the escalation increase from the year 2000 is shown in Figure 2. IPA models also account for regional differences where they exist. Further details associated with cost adjustment can be found in Appendix H.

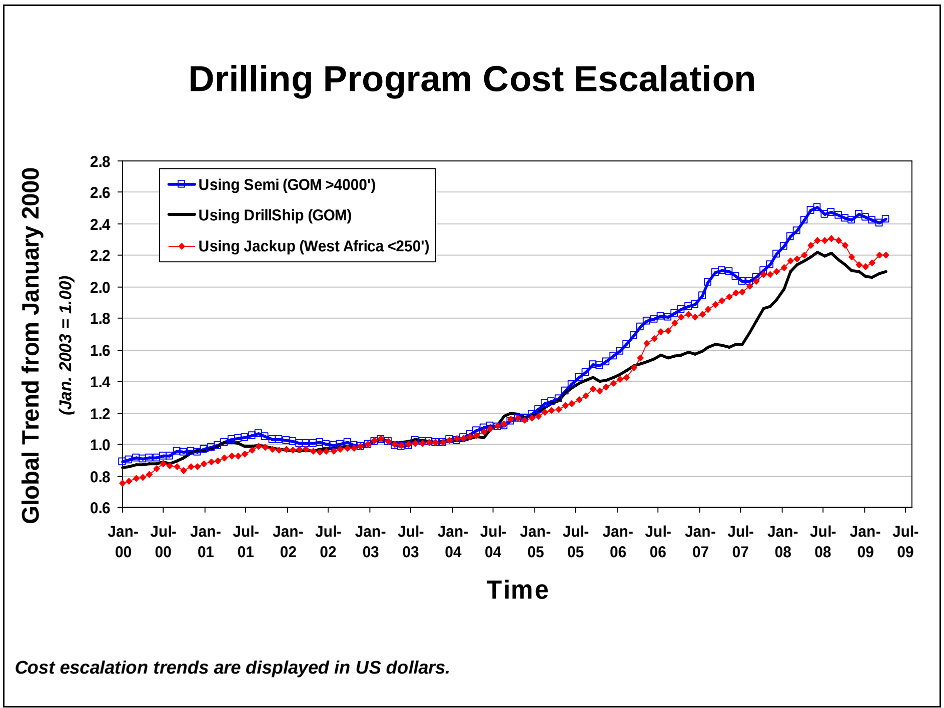


Figure 2

Table 13 shows the removal of escalation for the drilling rig cost included in the estimate at sanction. IPA has normalised for implicit escalation in the rig rate assumptions over the market rates at sanction. For Angsi-D, the TAD rig cost has an implicit escalation of US$57,742 per day, or a total of US$28 million was removed from the drilling cost estimate.

Table 13
IPA's Escalation Removal from the Drill Cost Estimates (US$) for the Angsi-D Project

	Contracted Day Rate (*T10*)	*Rig Logic* Average Rate	3-Month Rolling Average	Tender Rig from RIG Logic	D&C Days	Escalation Removed[23]
June 2007 to Sep 2007	$130,000	$72,878[24]	$72,259	26	485	$28,004,397

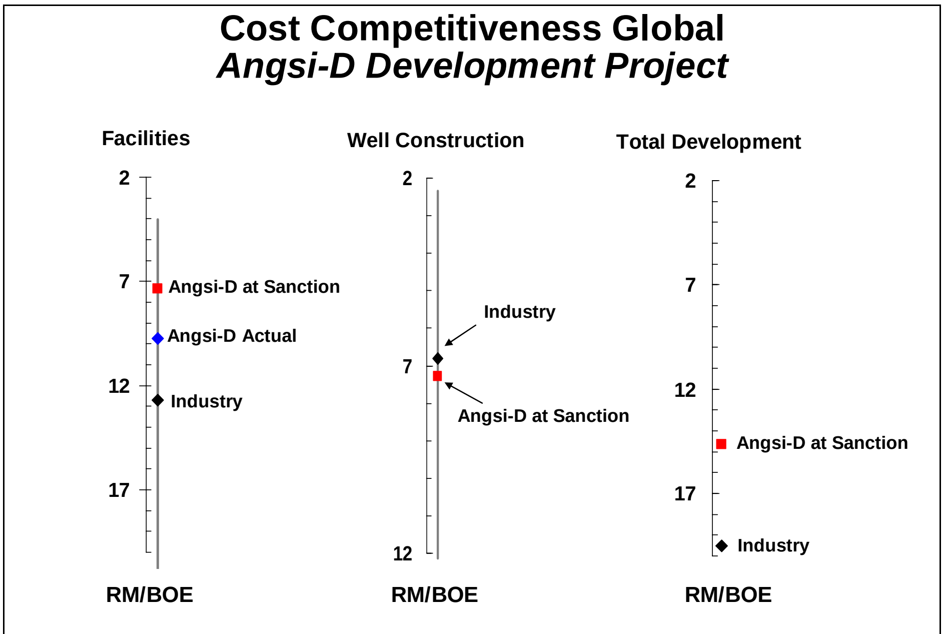
[23] The difference between the contracted rig rate and the 3-month rolling average was used to remove the escalation for the estimated drilling and completion days.
[24] Reference for September 2007.

Cost Deviation Normalisation

IPA's cost deviation methodology is based on de-escalating as-spent actual costs to the date of the estimate and then comparing the adjusted actual costs to the estimated costs. For the Angsi-D Development Project, the estimate date was September 2007.

Lump-sum contracts typically do not experience any escalation, so we do not make adjustments for this portion of the cost. Adjustments would only be for those costs that are under a reimbursable contract or other contracts in which the amount is not set for the sanctioned estimate. For the Angsi-D Development Project, the increase in the drilling rig rate and the additional costs for change orders (costs that are above the PCC lump-sum contract cost) in the facilities scope will therefore be adjusted.

Capital Cost per Barrel



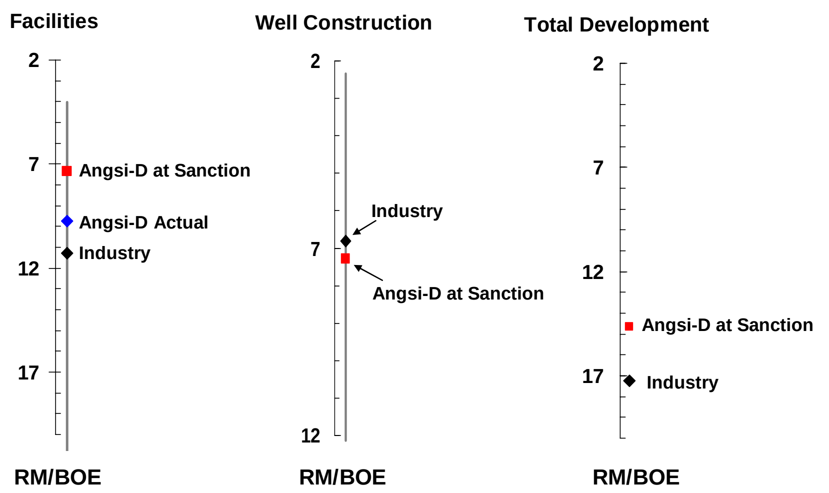
1. The bar represents the typical minimum and maximum cost ranges observed in Industry.
2. The benchmark includes the entire development (excluding export and onshore facilities).
3. Well Construction is not yet complete.

Figure 3

To assess the development costs, we compare the project's cost per barrel with that of other similar-sized fields. The cost per barrel comparison provides a consistent measure across all projects and provides a gauge for the cost effectiveness of a company in developing a field. It also provides a useful reflection on the quality of the asset development system when making critical decisions on asset development and concept type during front-end evaluation.

In Figure 3, we compare the Angsi-D Development Project's \$/BOE metric with global metrics for projects with a comparable resource promise (64 MMBOE) at similar water depths (71 m). The Angsi-D Development Project is an inexpensive development for its anticipated production stream. The lower than industry-average asset \$/BOE is driven by the cheaper facilities RM/BOE of approximately 10; the industry-average RM/BOE is 13.

Cost Competitiveness Asia
Angsi-D Development Project



1. The bar represents the typical minimum and maximum cost ranges observed in Industry.
2. The benchmark includes the entire development (excluding export and onshore facilities).
3. Well Construction is not yet complete.

Figure 4

As shown in Figure 4, we compared the Angsi-D Development Project's $/BOE metric with projects executed in Asia with a comparable resource promise (64 MMBOE) at similar water depths (71 m). The Angsi-D Development Project is comparable to industry-average asset $/BOE.

When comparing the project with both global and Asia datasets, the average wells $/BOE is industry average and is predominately driven by the lower than industry average[25] recovery per well and the moderate reservoir complexity. The industry average recovery per oil well is 11 million BOE per well; the Angsi-D field has a recovery of 6 million BOE per well.

The facilities $/BOE is better than the industry average. The low facilities $/BOE suggests either that Angsi-D selected the right concept to develop the reservoir or that this is an area well known by the project team and the field was easy to develop.

[25] Based on 16 projects with a similar-size resource promise and water depth.

Total Wells Concept Cost

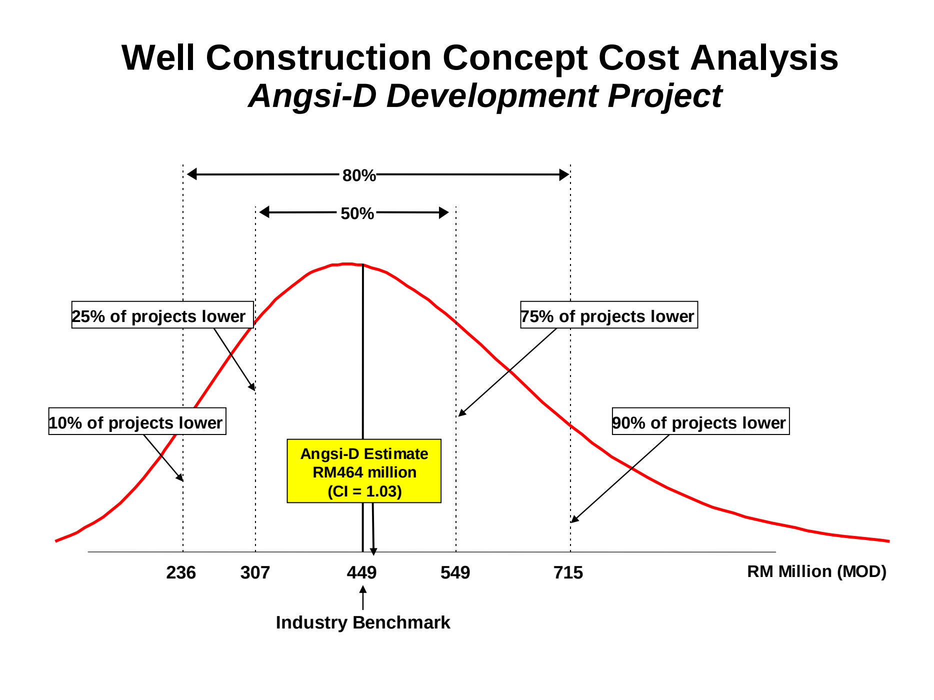


Figure 5

Figure 5 illustrates the concept cost benchmark[26] for the well construction program of the Angsi-D Development Project. The analysis creates a picture of the overall asset and identifies what Industry would spend regardless of the development plan chosen by the project team. Because the Concept Cost Effectiveness analysis does not "cloud" the issue based on the concept selected, it is especially useful in assessing whether or not the concept is cost effective. This metric takes into consideration the reservoir complexity.

The average cost for well programs to develop a life-of-project production stream similar to the Angsi-D Development Project is RM449 million. The project team's estimate of RM464 million is slightly higher than the industry average. The project team forecasts that the drilling cost will not deviate from the sanction drilling cost estimate. As explained previously, the recovery per well for the Angsi-D field is lower than industry average, which indicates that the wells concept for this field is not competitive. On average, Industry has six wells in a drilling program for a similar-size field. The Angsi-D Development Project planned for 11 development wells.

[26] Refer to Appendix G for a more detailed explanation of the Well Construction Concept Cost Metric.

Total Wells Component Cost

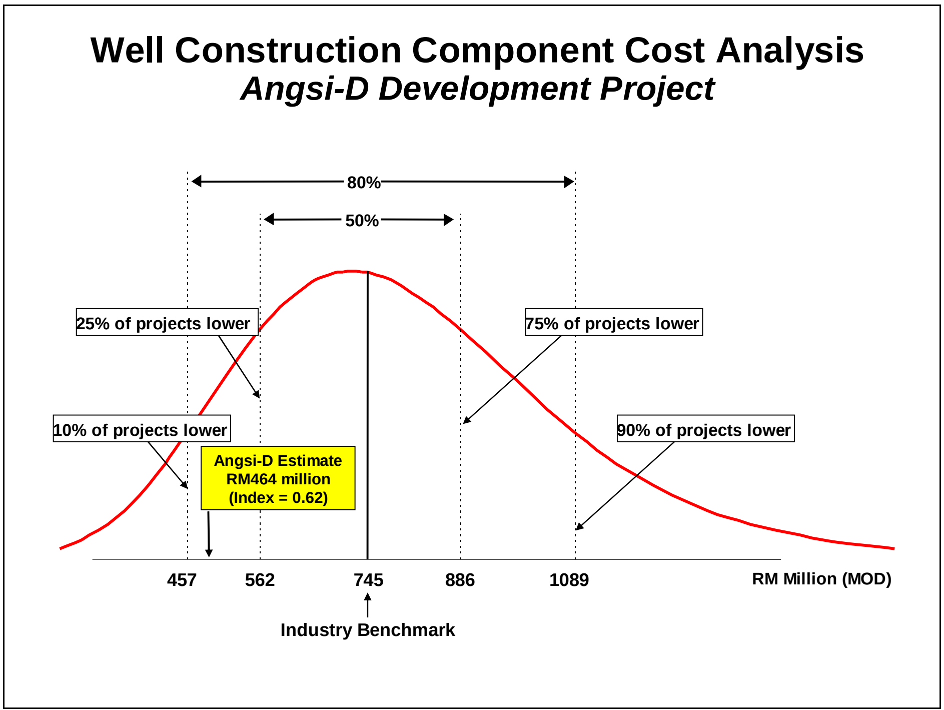


Figure 6

IPA's well program component cost effectiveness benchmark is intended to provide an industry average cost based on the specific design details of the well construction program (e.g., well count, well depth, rig type, and well complexity). The objective is to provide a benchmark of the program being built. The benchmark answers the question, "What would Industry spend, on average, to execute a well construction program of the same scope and complexity as the Angsi-D Development Project?" For the Angsi-D Development Project, the drilling scope of the 16-well program fits within the dataset envelope.

The measure of well complexity takes into consideration, among other things, the mud complexity, lost circulation, maximum mud weight, drilling difficulty and casing issues, the complexity of the well path, and the complexity of the completions. Other factors such as the type of rig used and the application of any new technology are also considered.

Figure 6 illustrates the component cost analysis[27] for the wells program of the Angsi-D Development Project. This analysis predicts the cost of a specific development plan regardless of whether it is the "right" plan. The major driver of the $/BOE and Concept Cost Effectiveness analysis is the resource promise estimate (RPE). Because the Component Cost analysis intends to look strictly at the development design and provide a cost benchmark, the major drivers are well count and well complexity.

The estimated wells construction cost at sanction for 11 wells was RM464 million, which is 38 percent lower than the industry average of RM745 million. The estimated cost per well for Angsi-D (based on the sanction cost of the 11 wells) is RM42 million, while the cost per well for

[27] Refer to Appendix G for a more detailed explanation of the Component Cost Metric.

the dataset of projects is RM68 million. This result is also consistent with the results of the recent drilling cost benchmarking[28] of the eight PCSB projects in Malaysian waters.

The drilling campaign has not been completed, and the team expects the wells design to change during the drilling campaign because of optimisation studies conducted after each completed well. The team forecasts that the actual cost of the drilling program will not deviate from the estimate.

Wells Construction Cost Summary

As shown above, the estimated wells program cost at the component level is competitive. The concept for this field and reservoir complexity is industry average as indicated by the cost index of 1.03. In turn, the concept significantly drove the Wells $/BOE index to 1.06, which indicates that the industry would typically pay slightly less to develop similar size reservoirs as the Angsi-D field. The project team planned to execute the drilling campaign efficiently, with a Wells Component Cost Index of 0.62.

IPA has normalised for implicit escalation in the rig rate assumptions over current market rates as explained previously.

Platform Cost

As mentioned previously, the WHP platforms cost metrics were calculated using UCEC data. The UCEC data do not account for variables such as water depth, maximum design wave height, conductor slots, if the WHP is unmanned or has installations for a tender assisted drilling rig, and do not differentiate between a processing platform and a minimal processing platform.

Table 14 summarises the comparison between the Angsi-D platform and UCEC data for projects executed in Asia and globally. The related UCEC charts are attached in Appendix A.

Table 14
AnDP-D Platform Comparison with UCEC Data

Platform	AnDP-D	Asia		Global	
		UCEC	Index	UCEC	Index
Jacket Weight (mt) For given Topside weight (1,587 mt) and water depth (71 m)	2,205	1,465		1,370	
Topside Weight (mt) For given Topside weight (1,587 mt) and Hydrocarbon Throughput (17 m)	1,587	1,247		1,369	
Actual Jacket Cost (RM^{MOD} million) For given Jacket weight (2,205 mt)	90	85	1.06	99	0.91
Actual Topside Cost (RM^{MOD} million) For given Topside weight (1,587 mt)	316	214	1.48	253	1.25
Actual Total Cost (RM^{MOD} million)	406	299	1.36	352	1.15

[28] Ghi, Trung, *Petronas 2007 Systems Benchmark (Upstream)*, June 2008, IPA.

The comparison table indicates that the jacket weight was heavier than other platforms in Asia and Globally for its topside weight and water depth. Topside weight was heavier than other topsides in Asia and Globally with the same throughput. For the given jacket weight, the Angsi-D Development Project team paid slightly more for the structure than similar projects in Asia; but less than similar projects globally. When comparing the given topside weight against other projects in Asia and Globally, the AnDP-D topside is more expensive (48 percent and 25 percent, respectively). Overall, the AnDP-D platform cost was 36 and 15 percent more expensive than other Asia and Global projects, respectively.

Pipeline Cost

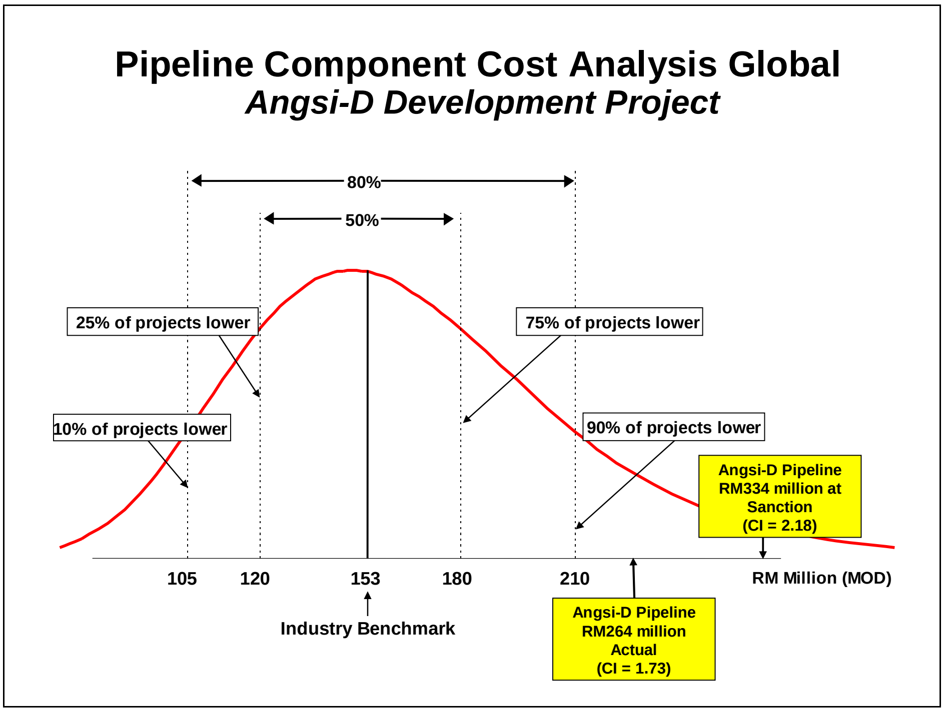


Figure 7

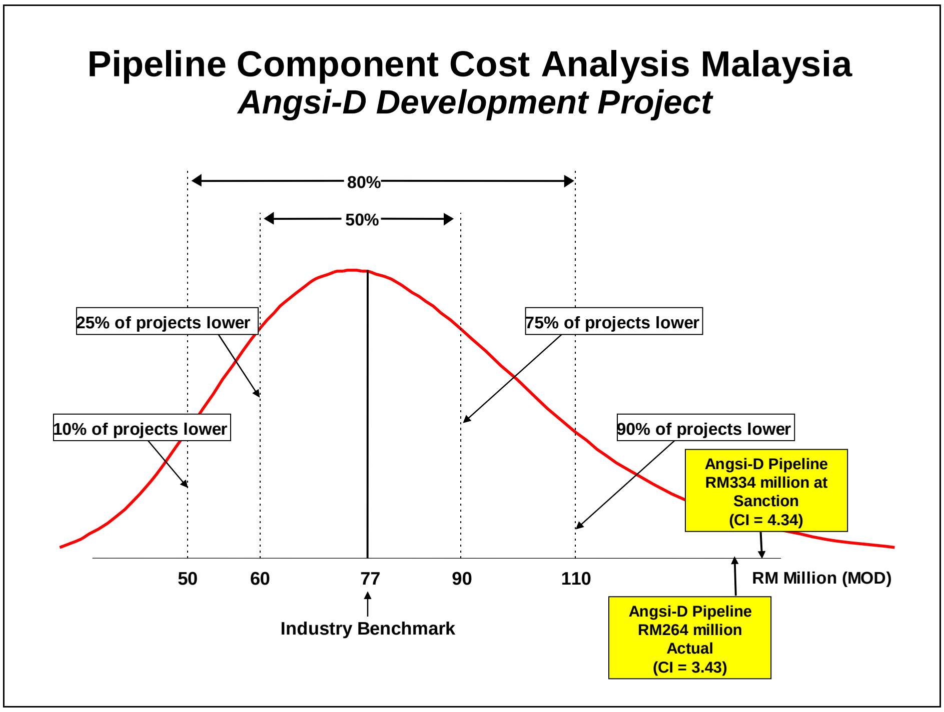


Figure 8

As shown in Figure 7 and Figure 8, the average industry cost to install intrafield pipelines similar to the Angsi-D Development Project pipelines was RM153 million (Global) and RM77 million (Malaysia). The project's estimate of RM334 million and actual cost of RM264 million are significantly more expensive than industry average.

Table 15
Gap Analysis Using PCSB Pipeline Projects

Category	Angsi-D	PCSB Project A	PCSB Project B	PCSB Project C	PCSB Project D
Diameter (in)	9.2	18	10	16	10
Length (km)	31	25	53	37	51
Maximum Water Depth (m)	71	72	57	172	72
Diameter x Length (in-km)	285	450	530	592	481
Total Actual Cost (RM million in MOD)	264	104	138	141	167
Actual Cost per Diameter x Length (RM million per in-km)	0.92	0.23	0.26	0.24	0.35
Cost Ratio Comparison with Angsi-D		4.02	3.56	3.90	2.66

Table 15 illustrates that the Angsi-D pipeline cost per in-km is significantly higher than the other PCSB pipelines (ranging from 3 to 4 times more costly per in-km). This is inline with the regional benchmark analysis provided in Figure 8.

Table 16
Comparison of PCSB Pipeline Projects

Cost Categories	Angsi-D	PCSB Project A	PCSB Project B	PCSB Project C	PCSB Project D
Component Cost Category (RM MOD)					
Office Cost	11	19	2	23	27
Fabrication	75	32	31	32	101
Transportation & Installation	175	51	102	85	29
HUC	2		2	-	-
Total	264	104	138	141	167
Predicted Cost Global	153	116	129	146	170
Cost Competitiveness Index	1.72	0.89	1.07	0.96	0.98
Index Ratio Comparison with Angsi-D		1.93	1.61	1.78	1.75

To understand which cost component needs further investigation by the team, Table 16 shows the component cost for Angsi-D and four other PCSB projects with a pipeline scope. These results clearly highlight the high transportation and installation and fabrication costs of the Angsi-D Project compared with other PCSB projects with similar pipeline dimensions.

The project team is currently investigating the installation costs with DFIN.

Facilities Cost Summary

As shown above and in Table 17, the pipeline and platform cost are more expensive than industry average for similar dry weights. The AnDP-D jacket dry weight is heavier than other jackets in Asia for a given topside dry weight and water depth. Based on a cost per tonne ratio, the AnDP-D topside is more expensive than other platforms in Asia and Globally. The jacket cost per tonne is slightly expensive compared with other platforms in Asia and Globally for similar jacket weights. Overall, the AnDP-D platform is expensive. The Facilities RM/BOE index of RM9.73 million per BOE is significantly more expensive than the industry average (RM12.72 million per BOE) in Malaysia. The chosen concept may not be suitable for the relatively small resource promise of 64 MMBOE, which is consistent with the observation that the jacket and topside weights are significantly high, or the resource may simply be relatively expensive to exploit.

Table 17
Angsi-D Development Facilities Cost Summary

	Estimate	Actual	Industry
Total Facilities Regional in RM million (Weighted Cost Index)	**804 (2.14)**	**670 (1.78)**	**376 (1.00)**
- AnDP-D WHP Platform in RM million (Cost Index)	470 (1.58)	406 (1.36)	299 (1.00)
- Pipeline in RM million (Cost Index)	334 (4.34)	264 (3.43)	77 (1.00)
Total Facilities Global in RM million (Weighted Cost Index)	**804 (1.60)**	**674 (1.33)**	**505 (1.00)**
- AnDP-D WHP Platform in RM million (Cost Index)	470 (1.34)	243 (1.15)	352 (1.00)
- Pipeline in RM million (Cost Index)	334 (2.18)	268 (1.72)	153 (1.00)

Cost Deviation

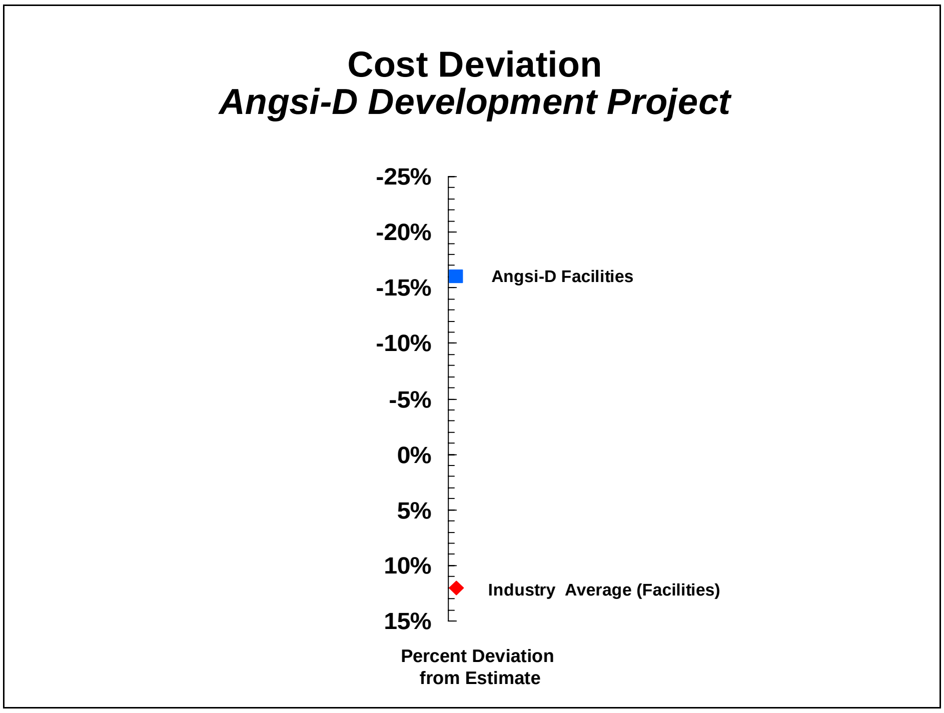


Figure 9

The actual cost of the Angsi-D Development Project's facilities scope was RM674 million; the estimated cost was RM804 million. The facilities cost deviation was therefore -16 percent, as shown in Figure 9. Historically, Industry has deviated from its facilities cost estimate by an average of 12 percent.

The approved PCC contract, used in the sanction cost estimate, was RM401 million. This amount was reduced through negotiations with the selected contractor post board approval to RM285 million. We used the approved estimate cost of RM470 million for the platform cost analysis and RM334 million for the pipeline cost analysis.

The team forecasts that the actual well cost will match the sanction cost.

Table 18
Cost Deviation Normalisation to May 2007 for the Angsi-D Development Project

	Estimate in September 2007		Actual in MOD	Actual Adjusted to September 2007	Cost Deviation at Estimate Date
	(RM Million)	(US$ Million)	(RM Million)	(US$ Million)	(1 Sept. 2007)
AnDP-D Platform	470	135	406	116	-14%
Pipeline	334	95	264	76	-20%
Total Facilities	804	230	670	192	-16%
Drilling	464	133	464[24]	133[24]	0%
Asset	1268	362	1134	325	-10%

At completion of the facilities scope, the actual cost of the PCC portion was RM670 million, which includes RM7 million for change orders from RFSB.

SCHEDULE

Table 19 summarises the Angsi-D Development Project schedule. The planned execution schedule was 27 months; the actual schedule was 32 months. Execution runs from the start of detailed engineering to mechanical completion or first hydrocarbons. This assumes that crucial systems are installed and commissioned at the time of first production (capability to export continuously). The estimated cycle time for this project (determined from the start of the Define phase to first hydrocarbon) was 29 months and the actual cycle time was 34 months. To meet the PCSB oil production, the team was required to deliver first oil by December 2008. The project team achieved first oil in May 2009.

Table 19
Schedule for the Angsi-D Development Project

Project Phase	Plan			Actual		
	Start	Finish	Months	Start	Finish	Months
Angsi-D Appraisal Drilling	22-Mar-99			22-Mar-99		
Pre-Development	18-Nov-05	07-Jun-06	6.6	18-Nov-05	07-Jun-06	6.6
CMC Project Sanctioned	18-Nov-05			18-Nov-05		
FDP Process & Approval	09-Dec-05	09-Mar-06	3.0	09-Dec-05	09-Mar-06	3.0
Overall Contracting Strategy	16-May-06	07-Jun-06	0.7	16-May-06	07-Jun-06	0.7
Project Select (FEL 2)	18-Nov-05	20-Jul-06	8.0	02-Aug-04	17-Nov-05	15.5
Define (FEL 3)	21-Jul-06	10-Sep-06	1.7	21-Jul-06	10-Sep-06	1.7
Detailed Engineering	11-Sep-06	30-Mar-07	6.6	11-Sep-06	01-Dec-06	2.7
Authorization Date	23-Nov-07			23-Nov-07		
SPJ + WHP						
Procurement	27-Jun-06	04-Sep-08	26.3	27-Jun-06	28-Aug-08	26.1
Fabrication	23-Jun-06	02-Sep-08	26.4	23-Aug-06	30-Oct-08	26.3
Contracting	23-Jun-06	19-Apr-07	9.9	23-Aug-06	13-Feb-07	5.7
Jacket	08-Nov-07	04-Jul-08	7.9	08-Nov-07	08-Sep-08	10.0
Topsides	08-Nov-07	02-Sep-08	9.8	08-Nov-07	30-Oct-08	11.7
Transportation and Installation	05-Jul-08	08-Aug-08	1.1	06-Oct-08	02-Nov-08	0.9
Jacket	05-Jul-08	08-Aug-08	1.1	06-Oct-08	02-Nov-08	0.9
Topsides	03-Sep-08	21-Sep-08	0.6	23-Oct-08	05-Nov-08	0.4
Offshore Hook-Up and Commissioning	22-Oct-08	07-Nov-08	0.5	06-Nov-08	05-May-09	5.9
Pipeline						
Procurement	18-Dec-06	05-Jan-07	0.6	18-Dec-06	05-Jan-07	0.6
Fabrication	05-May-07	17-Jul-07	2.4	06-Jan-07	27-Jul-07	6.6
Installation	22-Sep-08	20-Nov-08	1.9	01-Sep-07	10-Apr-09	19.3
Pre-lay First Part (12" & 6")				01-Sep-07	11-Oct-07	1.3
Pre-lay Second Part (10")				12-Aug-08	09-Sep-08	0.9
Risers				04-Dec-08	10-Apr-09	4.2
Offshore Hook-Up and Commissioning	22-Oct-08	07-Nov-08	0.5	06-Nov-08	20-Apr-09	5.4
First Monsoon Window	01-Nov-07	29-Feb-08	3.9	01-Nov-07	29-Feb-08	3.9
Second Monsoon Window	01-Nov-08	28-Feb-09	3.9	01-Nov-08	28-Feb-09	3.9
Drilling						
Rig Mobilisation	29-Oct-08	11-Nov-08	0.4	25-Mar-09	15-Apr-09	0.7
Development Drilling	12-Nov-08	02-Nov-09	11.7	16-Apr-09	*06-Apr-10*[29]	*11.7*[29]
Rig Demobilisation	03-Nov-09	16-Nov-09	0.4	*07-Apr-10*[29]	*20-Apr-10*[29]	*0.4*[29]
First Hydrocarbon	11-Dec-08			31-May-09		
Execution Duration	11-Sep-06	11-Dec-08	27.0	11-Sep-06	31-May-09	32.6
Cycle Time	21-Jul-06	11-Dec-08	28.7	21-Jul-06	31-May-09	34.4

[29] Projected

Facilities Execution Schedule

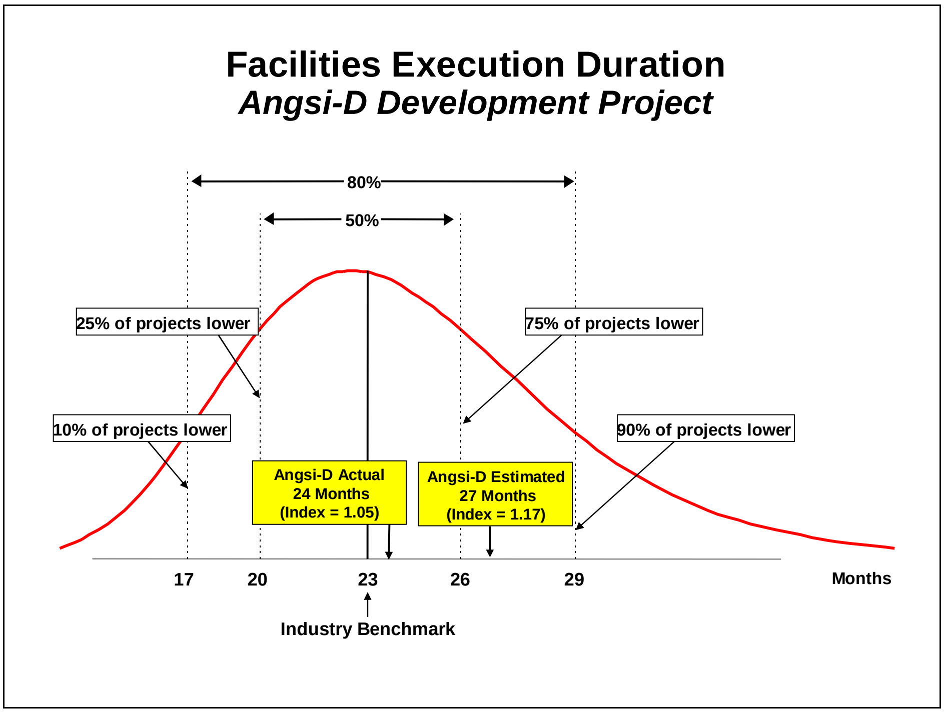


Figure 10

As shown in Figure 10, the planned execution duration of the Angsi-D Development Project was 27 months, which is slower than the industry average of 23 months. The actual time needed to execute the Angsi-D Development Project was 32.6 months. After removing the effects of the legal delay, this becomes 24 months, which is 4 percent slower than Industry. Standardisation of the WHP and pipelines from previous Angsi developments were key factors that enabled the achievement of this schedule. The project schedule was hurt by the two monsoon weather periods.

Well Construction Schedule

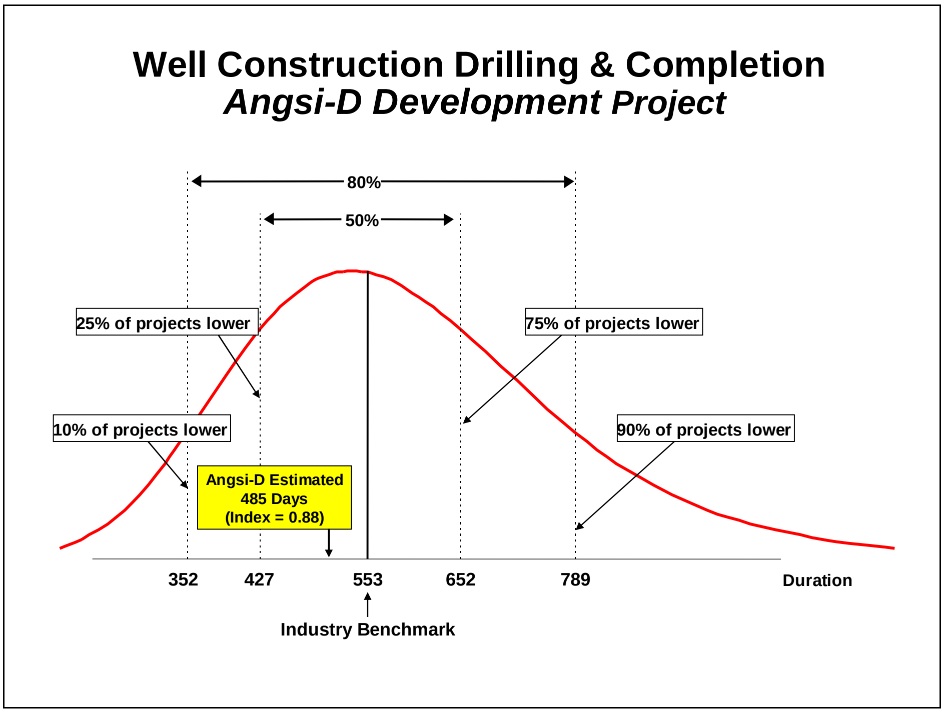


Figure 11

As shown in Figure 11, the planned well construction drilling and completion duration of the Angsi-D Development Project is 485 days, which is faster than the industry average of 553 days. The wells program has had design changes due to the aggressive appraisal and optimisation of the depletion plan. To date, the team has drilled the first well for the program but has encountered problems with the blowline valve. The team anticipates the drilling campaign to be completed by April 2010, which would maintain the original wells program duration.

Schedule Deviation

The Angsi-D Development Project underran its planned execution schedule by 13 percent while the industry average is an overrun of 19 percent. PCSB's average schedule deviation is 12 percent. This percentage is calculated by dividing the difference between the actual and planned execution durations by the planned execution duration. The planned schedule was considered aggressive by the team. The main drivers of the schedule underrun were from shortening detailed engineering, awarding pipeline fabrication contract pre-sanction, and ordering of long-lead equipment pre-sanction.

PROJECT PRODUCTION STREAM AND OPERABILITY

Completing a project predictably, cheaply, and quickly will not benefit the business unless it operates satisfactorily, and anticipated value is realised.

IPA evaluates the degree to which life-of-project production stream estimates change during the execution and early production stages of the project, as further reservoir evaluation and early reservoir management change the perception of the reservoir.

IPA also assesses production attainment, the ratio of actual production in the second 6 months of operation (to allow for a settling-in period and to adjust for schedule slips) compared to the production profile planned at sanction.

The Angsi-D Development Project's plan represents the most likely development outcome that corresponds with Proven + Probable reserves criteria. However, the team created low side and high side reserves expectations that correspond with Proven + Probable + Possible reserves criteria. The development plan incorporates certain options that form the Alternate Development Plan. This plan reflects the downsides from uncertainties applying to the low-side outcome and upsides from opportunities applying to the up-side outcome.

The actual implementation of any one of these plans depends on the development drilling results and additional analyses of those results. For example, some uncertainty is associated with the structure of the reservoir.

The Angsi-D Development Project's wells campaign is ongoing; therefore, this metric cannot be determined. At sanction, the recoverable resource promise was expected to be 64 MMBOE. At the time of the project interview, an optimisation study decreased the estimated recoverable resource promise to 42 MMBOE. This is an estimated downgrade of 34 percent of the total resource promise. This result is in line with IPA's Appraisal Effectiveness Index (AEI), as shown in Figure 12.

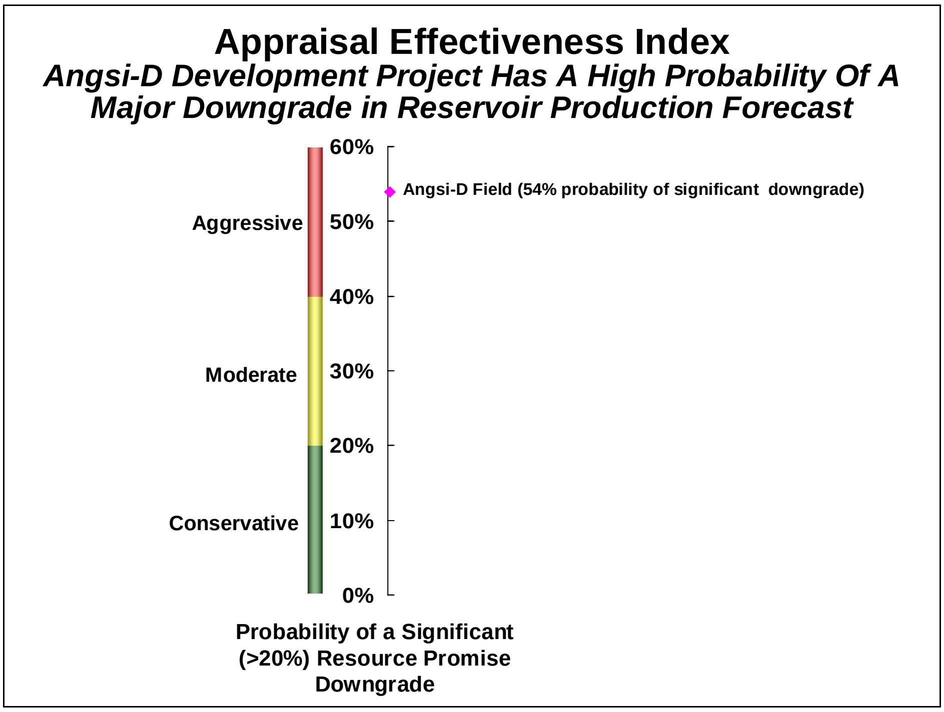


Figure 12

Based on the reservoir characteristics and the effectiveness of the appraisal program in gathering all key data, our analysis (based on historical industry performance) suggests the likelihood of more than a 20 percent downgrade in reservoir production forecast. The Angsi-D field has a 54 percent probability of a downgrade of at least 20 percent, based on the subsurface efforts.

Operability/Production Attainment

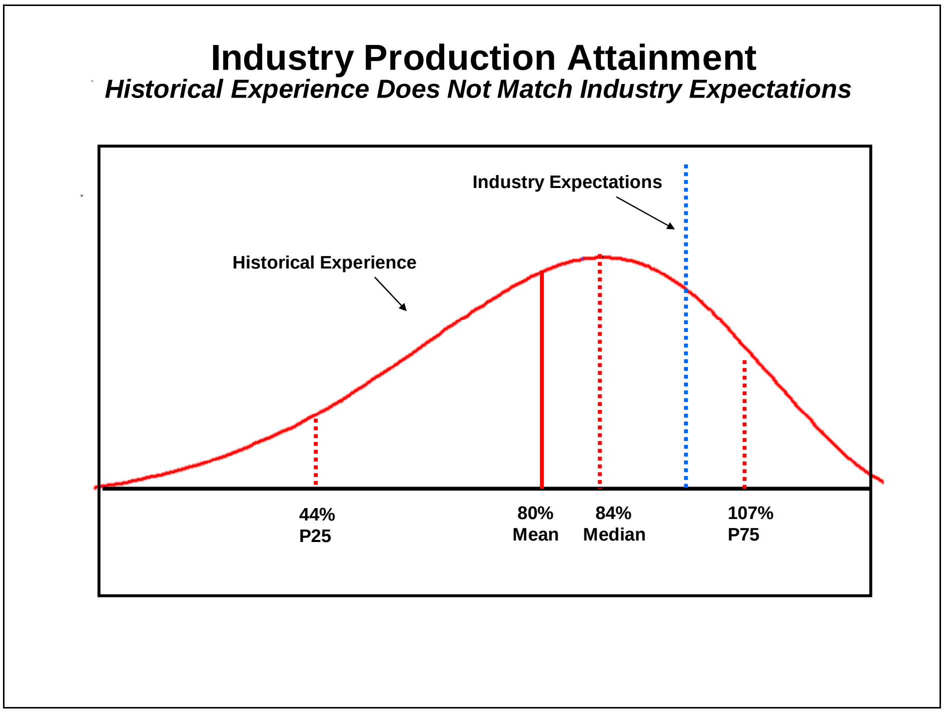


Figure 13

For the Angsi-D Development Project, it is too early to determine operability outcomes, but the team expects to be able to export oil continuously and to have the system fully operational by June 2009.

PROJECT PRACTICES AND DRIVERS

IPA has found a statistical relationship between certain project characteristics and project results. We focus on the drivers because they are the key factors that either (1) the team needs to be aware of when assessing project economics; or (2) more importantly, *that the team can change to improve the likelihood of project success*. This section provides the results of our analysis of the key project drivers listed below:

- Appraisal philosophy
- Subsurface complexity
- Level of definition (or Front-End Loading)
- Team Development Index (TDI)
- Use of applicable Value Improving Practices (VIPs)

APPRAISAL PHILOSOPHY

Appraisal Strategy is a key factor affecting both project drivers and project outcomes. Generally, asset developments are characterised by a *Conservative*, *Moderate*, or *Aggressive* approach, depending on the completeness and quality of the subsurface data that are being used in the project. Each approach has implications for the risks and benefits that are carried forward into project execution.

The Angsi 3D seismic data used were from 1995 and were reprocessed in 2000. In August 2004, one appraisal well penetrated the reservoir I-27/35U. This appraisal well supplied fluid content, structure, stratigraphy, core, and pressure MDT data. At sanction, the data available were from one appraisal well and from wells drilled in the Angsi Field in previous phases. Therefore, given the size of the field, the number of the wells penetrated, and the subsurface data available, the Angsi-D Development Project had an *Aggressive* appraisal strategy.

Areas of risk include uncertainty associated with the structure across the field. I-100 reservoir was penetrated by Angsi-8 and rest of the reservoirs (I-15L, I-75, I-85) were appraised using the information from previous wells drilling in Angsi Field.

SUBSURFACE COMPLEXITY

Reservoir Complexity and *Wells Complexity* are used to assess the subsurface conditions and characteristics of the wells programs used in asset development projects. Higher complexity ratings can increase project risks. The following two sections describe the complexity rating and issues that affected the Angsi-D Development Project.

Reservoir Complexity

The Reservoir Complexity Index (RCI) for the Angsi-D reservoirs is 36, which is similar to the average PCSB RCI of 37; the industry average RCI is 39. The Angsi-D I-27/35U reservoir has the following characteristics: minimal fractures and faults, no compartmentalisation, low stacking with moderate vertical continuity and low lateral continuity, semi-continuous barriers, moderate rock quality, light hydrocarbon and minor formation water, moderate aquifer and gas cap, low compaction drive, and little reservoir energy. The other reservoirs are similar; however, the main differences are the reservoir energy is higher and the I-100 reservoir has high stacking.

Wells Complexity

The production wells are more complex than industry average and are similar to the PCSB averages. The Angsi-D wells consist of 11 wells and 5 optional wells. There are 10 producer wells, 3 gas injector wells, and 3 water injector wells. The Wells Complexity Index (WCI) for the 11 wells ranges from 52 to 55; industry average is 52 and the PCSB average is 49. The team had to design the wells to incorporate possible adverse gases and low mud weight. The completion designs include gas lift, formation evaluation and logging, but do not include sand controls. The original well designs were for single-string and dual-string completion. Some wells have angles of more than 70 degrees.

FRONT-END LOADING

Front-End Loading (FEL) is a measure of the definition of a project; FEL provides a picture of the project's readiness for execution and level of risk and is a major driver of project outcomes. IPA determines the *Asset FEL Index,* a measure of the project's overall level of definition, by considering together the FEL indices for three E&P disciplines: (1) Reservoir FEL, (2) Wells FEL, and (3) Facilities FEL.

Reservoir Front-End Loading

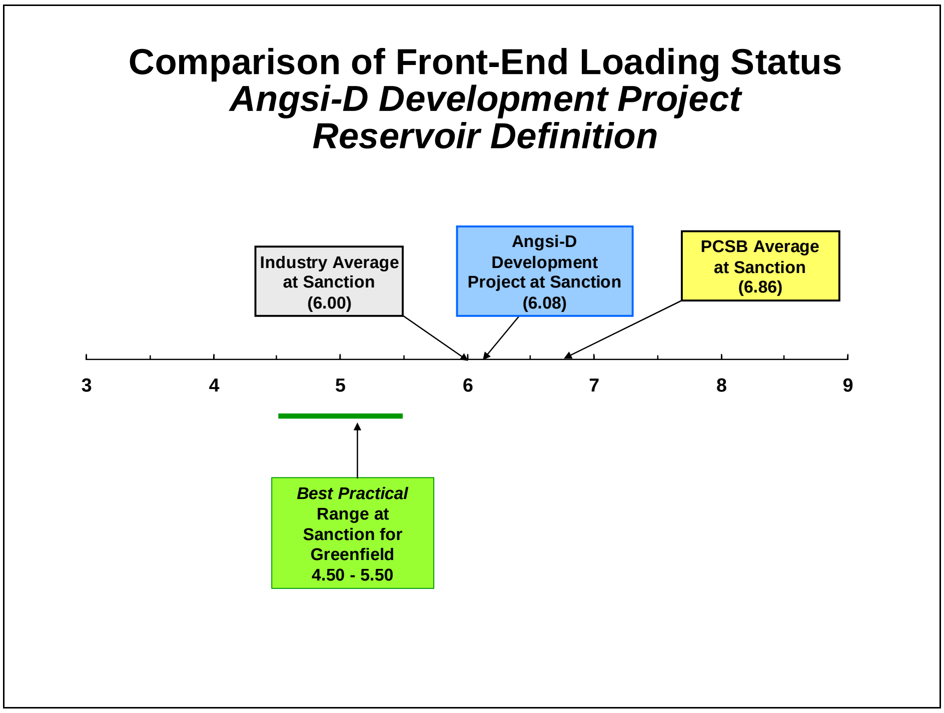


Figure 14

The most leveraging of the three FEL measures is Reservoir FEL because it develops the basic data for the asset development: It is the premise of the project. When project teams lack adequate basic reservoir data, the advancement of Facilities and Wells FEL is constrained and project outcomes, as a rule, are disappointing.

Figure 14 illustrates the Reservoir FEL Index for the Angsi-D Development Project. The Reservoir FEL Index was 6.08, which falls outside the *Best Practical* range of 4.50 to 5.50 for greenfield developments at sanction. The average Reservoir FEL Index for PCSB projects at sanction is 6.86 and the industry average is 6.00.

The four components of Reservoir FEL are (1) Inputs, (2) Constraints, (3) Tasks and (4) Reservoir Evaluation Execution Planning. We provide the ratings for each of the components of the Reservoir FEL Index in Table 20.

Table 20
Angsi-D Development Project Reservoir Front-End Loading (at Sanction)

FEL Component	**Angsi-D Development Project**		***Best Practical* for Greenfield Developments**	
Inputs	*Assumed*	*(3)*	*Definitive*	*(1)*
Constraints	*Preliminary*	*(2)*	*Preliminary*	*(2)*
Tasks	*Definitive*	*(1)*	*Definitive*	*(1)*
Planning (overall)	*Preliminary*	*(2)*	*Definitive*	*(1)*
Reservoir FEL	6.08		4.50 to 5.50	

Inputs

Inputs were *Assumed*, which lags the *Best Practical* rating of *Definitive* for greenfield developments. The subsurface team had sufficient logs and 3D seismic data across the field for the Angsi-D. The core data were obtained from side-wall cores in the Angsi-B area; therefore, the project team had to infer the Angsi-B porosity and permeability properties. As mentioned in the Appraisal section, the team drilled one appraisal well (Angsi-8), which provided the fluid content, structure, and stratigraphy data. Well tests were not conducted.

Constraints

Constraints were *Preliminary*, which is *Best Practical* at sanction. The single major constraint was the timing for the subsurface evaluation. The Angsi-D Development Project was a fast-tracked project; therefore, the subsurface team had schedule pressure to minimise the time spent on subsurface activities. In fact, the majority of the key activities were performed in parallel with the wells and facilities activities.

Tasks

Tasks were *Definitive*, given the data available, which is *Best Practical* at sanction. The team performed 3D geological modelling and PVT. Fluid characterisation was understood by the team and documented in the FDP. All seismic interpretations were done. The drive mechanism was known and the aquifer was identified. Specific well locations have been mapped out but these locations will change depending on how each well performs. The reserves profile has been developed and is being updated regularly as new drilling information is obtained. The team captured risk and uncertainty in the risk register.

Planning

Reservoir Execution Planning was *Preliminary*, which lags the *Best Practical* rating of *Definitive* at sanction. The subsurface team was dedicated to the Angsi field development, and the team's size and composition were adequate for the Angsi-D scope of work. Roles and responsibilities were established for each team member but they were not documented. Project objectives were established and understood by all team members. Data acquisition plans were developed and agreed on with the drilling team. The FDP was approved.

The team did not reach *Best Practical* for this component because a detailed subsurface schedule, which includes subsurface activities during execution, was not developed at sanction.

Well Construction Front-End Loading

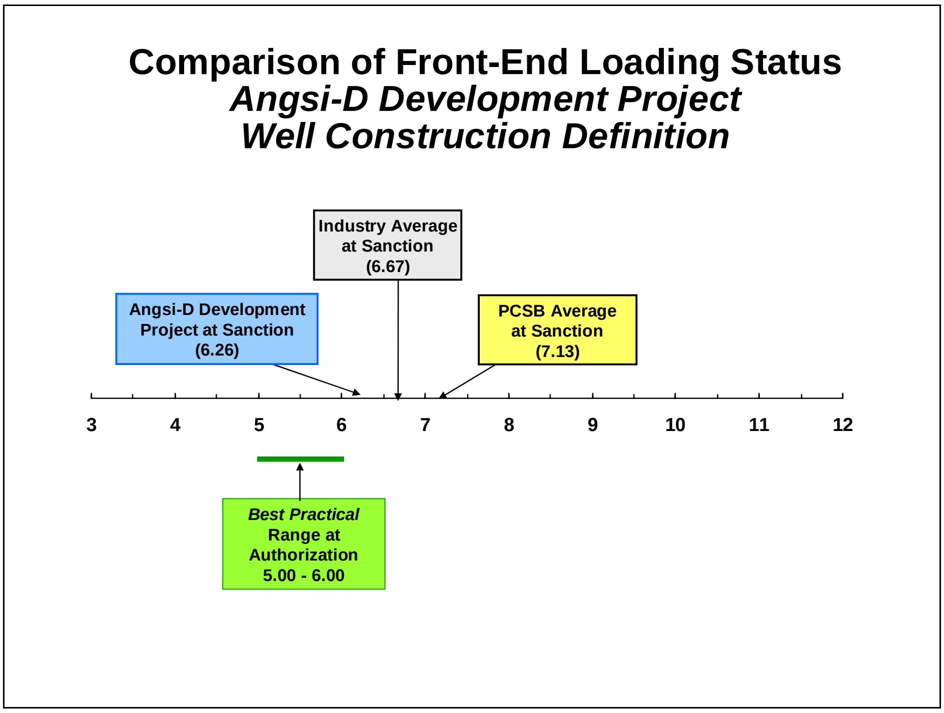


Figure 15

As shown in Figure 15, the Angsi-D Development Project's Well Construction FEL Index is 6.26, which falls outside of the *Best Practical* range for projects at sanction. The industry average Well Construction FEL Index is 6.67 and the PCSB average is 7.13. The four components of Well Construction FEL are (1) Scope of Work, (2) Regulatory/Health Safety and Environment, (3) Well Engineering, and (4) Well Project Execution Planning and Scheduling. We provide the ratings for each component of the Well Construction FEL Index in Table 21.

Table 21
Angsi-D Development Project Well Construction Front-End Loading (at Sanction)

FEL Component	Angsi-D Development Project		*Best Practical*	
Scope of Work	*Definitive*	*(1)*	*Definitive*	*(1)*
Regulatory/HSE	*Preliminary*	*(2)*	*Preliminary*	*(2)*
Well Engineering	*Preliminary*	*(2)*	*Preliminary*	*(2)*
Well Planning	*Assumed*	*(3)*	*Preliminary*	*(2)*
Wells FEL	6.26		5.00 to 6.00	

Scope of Work

The Scope of Work was *Definitive*, which is *Best Practical* at sanction. Soil bed strength and weather conditions were known, the commercial plan and schedule were developed, and the well objectives and scope were defined. Based on the results of an ongoing optimisation study from the subsurface at sanction, the well number may change. However, the team designed the wells to incorporate possible adverse gases and mud loss. The original well designs were for single- and dual-string completion, and some have angles that are more than 70 degrees.

Regulatory/HSE

The Regulatory/HSE was *Preliminary*, which is *Best Practical* at sanction. The project team identified the necessary permits, and import conditions were known and incorporated into the cost estimate. A HAZOP study for drilling was developed at sanction, and a mitigation plan was in place. The team had more than 10 years of experience in the Angsi field, and regulatory and environmental issues were addressed in previous projects. Therefore, this FEL component was viewed as a low risk.

Well Engineering Status

The Well Engineering Status was *Preliminary*, which is *Best Practical* at sanction. Preliminary well designs were developed through an ongoing optimisation study. The project team elected to have flexibility in the depletion plan. The team identified the long-lead items, but did not place orders at sanction.

Well Planning

Well Planning was *Assumed*, which lags the *Best Practical* rating of *Preliminary* at sanction. A young core team had been assembled. Rig candidates had not been identified at sanction. A preliminary cost estimate was prepared at sanction, but individual AFEs were only prepared as the drilling campaign moved forward.

The team did not achieve *Best Practical* for this component because a suitable rig was not secured and individual AFEs were not developed at sanction to support an accurate cost estimate.

Facilities Front-End Loading

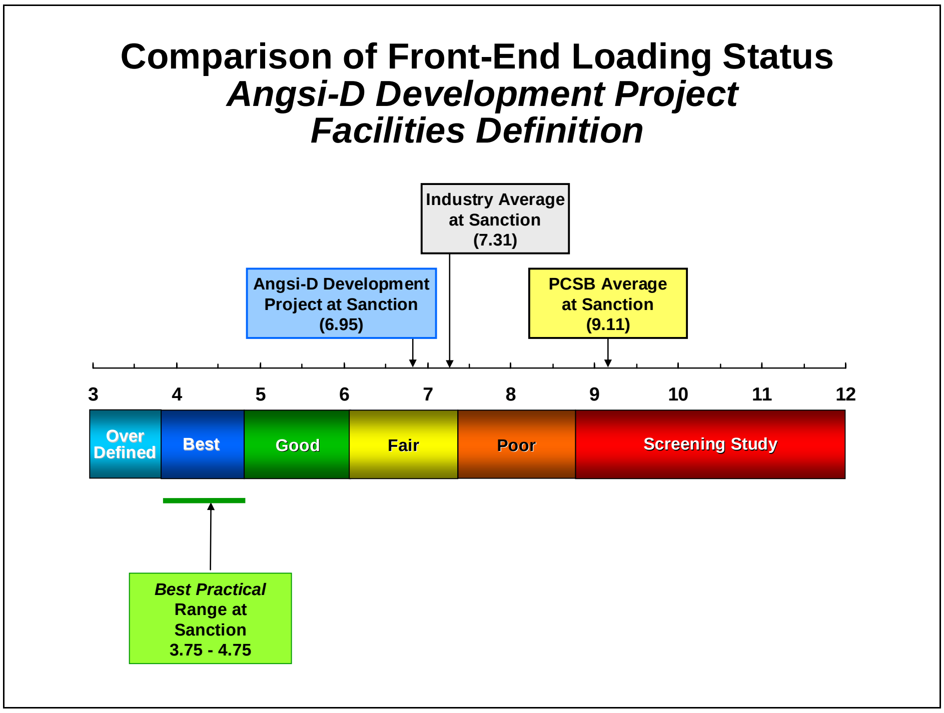


Figure 16

Figure 16 illustrates the FEL Index for the Angsi-D Development Project facilities. The project has an FEL Index of 6.95, which is *Fair*. This rating matches the industry average (also *Fair*), but trails the *Best Practical* range (3.75 to 4.75) at sanction. The Angsi-D Development Project's definition was better than the PCSB average FEL Index, which is 9.11 (*Screening*).[30]

The four components of Facilities FEL are (1) Project-Specific Factors, (2) Project Execution Planning, and (3) Engineering Status. We provide ratings for each component of the Facilities FEL Index in Table 22.

Table 22
Angsi-D Development Project Facilities Front-End Loading (at Sanction)

FEL Component	Angsi-D Development Project		*Best Practical*	
Project-Specific Factors	*Preliminary*	*(1.73)*	*Definitive*	*(1)*
Project Execution Planning	*Assumed*	*(3.00)*	*Definitive*	*(1)*
Engineering Status	*Advanced Study*	*(2.00)*	*Advanced Study*	*(2)*
Facilities FEL	6.95 *(Fair)*		3.75 to 4.75	

[30] The PCSB projects were based on projects used in the baseline assessment in 2007, and the majority of the projects were sanctioned after the FDP approval, which was before the Define phase or FEL 3.

Project Specific Factors

Project Specific Factors were *Preliminary*. *Best Practical* for this component at sanction is *Definitive*. The team collected a small set of soil borings at the platform location and completed the soil analysis. The location platform was locked down. Site-specific regulations were identified, but the team had limited contact with the appropriate agencies. The development plan met all of the lease requirements, and the government agencies had signed off. Local import material requirements were understood and incorporated into the cost estimate. Local content requirements were identified and a plan was developed. The community representative was fully involved and the quartering facilities were identified.

Project Execution Planning (Overall)

Project Execution Planning was *Assumed*. *Best Practical* for this component at sanction is *Definitive*. Business and project objectives were defined, and the team was aligned on these objectives. The project team had an operations representative to provide input to the project design. A Project Execution Plan (PEP) was developed and distributed to the project team. A milestone schedule was developed; but it didn't include any resources and work breakdown structure (WBS) that can be use for project control. The contracting strategy was defined and approved by PCSB. Roles and Responsibilities were defined but were not documented.

The team did not achieve *Best Practical* for this component because a detailed, networked schedule with resource-loading and a detailed WBS was not developed.

Engineering Status

Engineering Status was *Advanced Study*, which is *Best Practical* for this component at sanction. To assist with the schedule pressure, the team used the Angsi-B WHP design to shorten the time for design. Detailed engineering was done before sanction (as approved by management). Given this, the level of definition for this component should be at *Full Design Specifications*. However, based on the lack of detail in the cost estimate, the rating was downgraded to *Advanced Study*. The overall cost estimates were at a high level and were mostly based on historical data. The piping and instrumentation diagrams (P&IDs) were approved by the Technical Review Committee before sanction. Equipment data sheets were completed, and design-bid packages were ready to be awarded at sanction. The fabricator was selected, and the piping layout was completed. Preliminary quotes were obtained for a number of key items.

PIPELINE FRONT-END LOADING

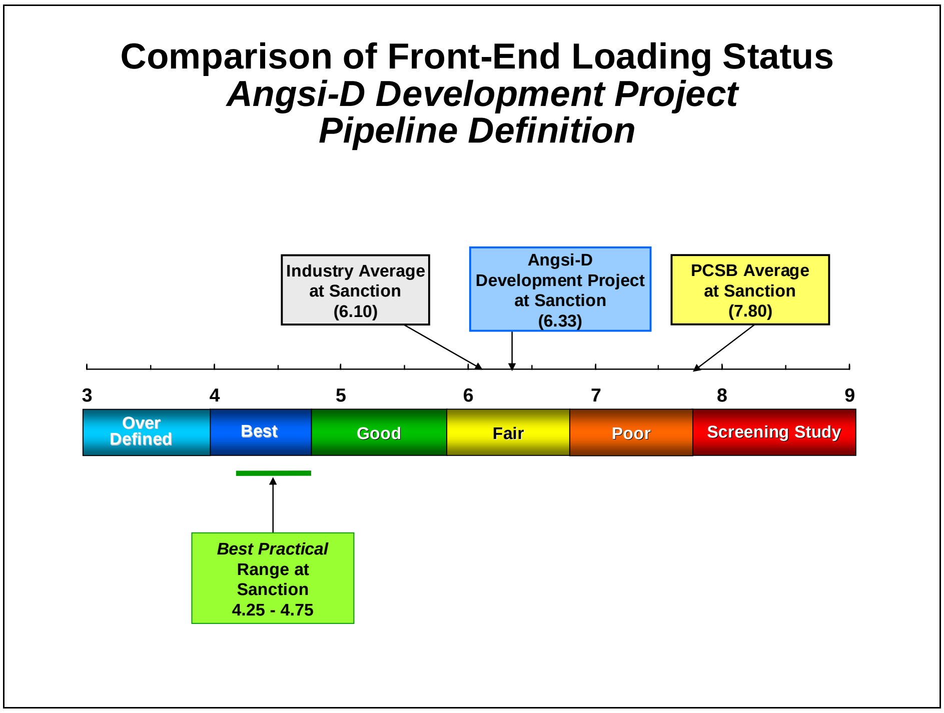


Figure 17

Figure 17 illustrates the Pipeline FEL Index for the Angsi-D Development Project. The Pipeline FEL Index was 6.33 (*Fair)*. This rating matches the industry average (also *Fair*) but is better than the PCSB average of 7.80 (*Screening Study*). The *Best Practical* range at sanction is 4.25 to 4.75. We provide ratings for each component of the Pipeline FEL Index in Table 23.

Table 23
Angsi-D Development Project Pipeline Front-End Loading (at Sanction)

FEL Component	**Angsi-D Development Project**		***Best Practical***	
Site Factors	*Definitive*	(1.33)	*Preliminary*	(1.75)
– Route Definition	– *Definitive*		– *Definitive*	
– Seafloor/Terrain Conditions	– *Definitive*		– *Definitive*	
– Right of Way	– *Definitive*		– *Preliminary*	
– Community Issues	– *Definitive*		– *Definitive*	
– Health and Safety	– *Preliminary*		– *Definitive*	
– Permitting/Environment	– *Preliminary*		– *Preliminary*	
Project Execution Planning	*Assumed*	(3.00)	*Definitive*	(1.00)
Engineering Status	*Advanced Study*	(2.00)	*Advanced Study*	(2.00)
Pipeline FEL	6.33 (*Fair*)		4.25 to 4.75	

Site Factors

The Site Factors component was *Definitive. Best Practical* at sanction is *Preliminary*. The pipeline route survey and soil samplings were done. The soil samples were analysed and incorporated into the pipeline designs. No community and permitting issues were identified. The Angsi-D field belongs to PCSB as part of the PSC agreement, and therefore the project did not have any issues with right of way.

Project Execution Planning

Project Execution Planning was *Assumed*, which lags the *Best Practical* rating of *Definitive* at sanction. The pipeline scope falls under the overall project execution plan, which is discussed in the Facilities FEL section. The pipeline installation vessels were sourced from TLO under the PCSB umbrella contract. Similarly, pipeline material was sourced from MJSB under the PCSB umbrella contract.

Engineering Status

Engineering Status was *Advanced Study*, which is *Best Practical* at sanction. The pipeline design was conventional, and the project did not use any new technology. At sanction, the project team had completed detailed design, heat and material balances, and seafloor surveys. All designs were approved by Operations. The pipeline materials were procured and fabrication was completed. The installation package was ready to be awarded. Similarly to the facilities discussion previously, the pipeline Engineering Status should be rated as *Full Design Specifications* based on the completed detailed design. However, because of the lack of detail in the pipeline cost estimate, the rating was downgraded to *Advanced Study*.

Overall Asset Front-End Loading

Research on overall asset outcomes has shown that a combined index—the Asset FEL Index—is correlated with overall asset performance. The correlation is strongest when the component FEL Indices are combined in the ratio 2:1:2. Thus, the Asset FEL is calculated as the sum of 40 percent Reservoir FEL, 20 percent Wells FEL, and 40 percent Facilities FEL.

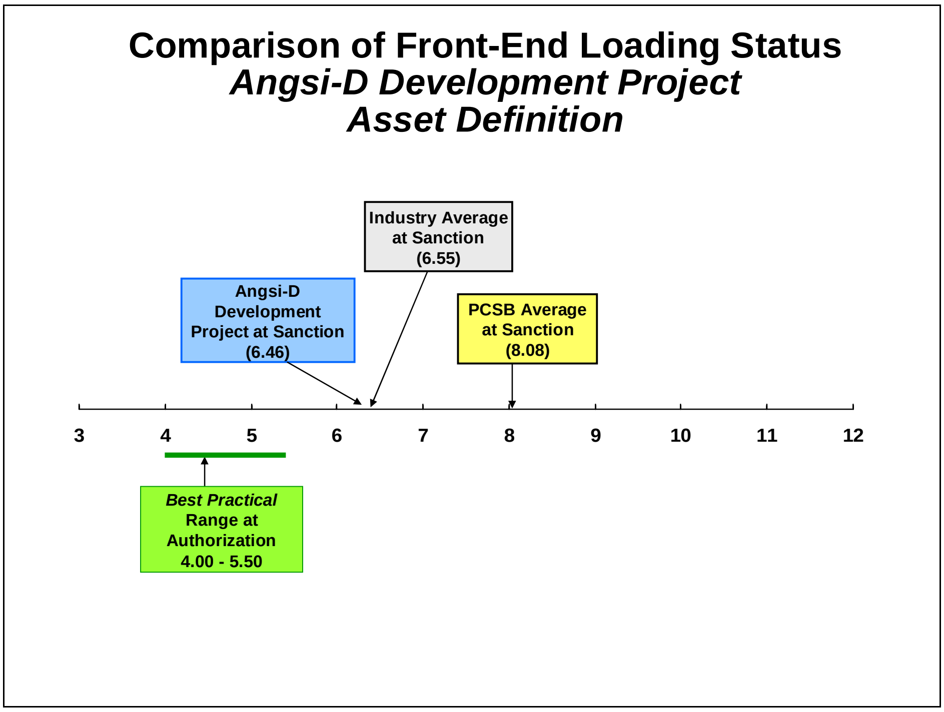


Figure 18

Figure 18 illustrates the Asset FEL Index for the Angsi-D Development Project. The project has an Asset FEL Index of 6.46. This rating is similar to the industry average, and falls outside of *Best Practical* (4.00 to 5.50) at sanction. Table 24 compares the Asset FEL Index and its components for the Angsi-D Development Project with the *Best Practical* level for a project with similar characteristics.

Table 24
Angsi-D Development Project Asset Front-End Loading Index

FEL Component	Project at Sanction	*Best Practical*	Industry Average
Reservoir FEL	6.08	4.50 to 5.50	6.00
Facilities FEL	6.95	3.75 to 4.75	7.31
Wells FEL	6.26	5.00 to 6.00	6.67
Asset FEL	***6.46***	***4.00 to 5.50***	***6.55***

TEAM DEVELOPMENT INDEX

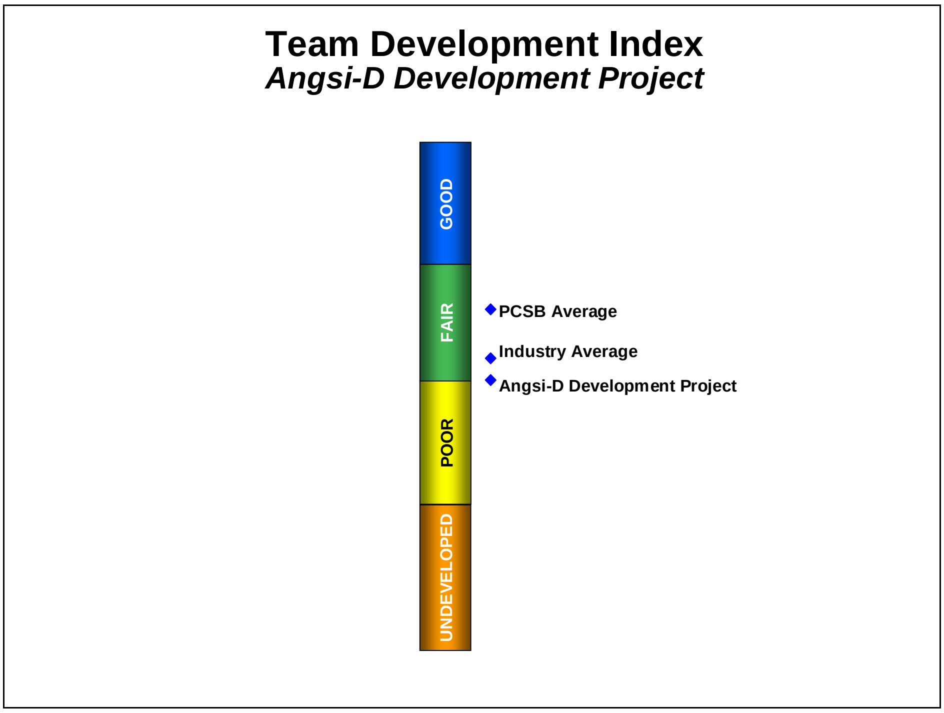


Figure 19

As shown in Figure 19, the Angsi-D Development Project had a Team Development Index (TDI) in the *Poor* range, which is worse than the industry and PCSB averages of *Fair*. For a detailed explanation of IPA's TDI, please refer to the Team Development Index appendix. Note that the TDI has been validated only for onshore projects and is provided here only as a reference.

The TDI includes four components: project objectives, team composition, roles and responsibilities, and the project implementation process. Each component has an equal weight in the index. Below, we discuss the status of each component for the Angsi-D Development Project:

- **Project Objectives:** This element of the TDI measures whether the project has established objectives, whether the business objectives have been translated to project objectives, and whether the team understands the project's objectives. For the Angsi-D Development Project, project objectives were aligned with business objectives and were understood by the project team.
- **Team Composition:** This element of the index measures whether the team includes representatives from all functions that can influence project outcomes. Key project positions were filled for the Angsi-D Development Project.
- **Roles and Responsibilities:** This element includes whether roles and responsibilities have been defined for team members, whether problem areas have been identified, whether plans were developed to address these problem areas, and whether the team is aligned on the project's objectives and tasks. Roles and responsibilities were understood by the team members but were not documented. Risk registers were identified and plans to mitigate these risks were documented.

- **Project Implementation Process:** The TDI measures whether a common company project implementation process is in place and is understood by the team. Some team members were familiar with the PCSB Project Management Framework, but the project team deviated from the process. The FDP was completed and approved so that the project could continue on to the next phase. Engineering and procurement were approved before the project passed sanction because of the project schedule constraints.

The project team did not achieve a *Good* TDI because the project team deviated from the PCSB project delivery system. Historically, projects which deviate from the process have worse outcomes. Although the team members understood their roles and responsibilities, documenting the roles and responsibilities is best practice especially if project team turnover is frequent and the team members are relatively new to the team.

USE OF VALUE IMPROVING PRACTICES

Value Improving Practices (VIPs) are specific, formal practices or exercises that should normally be used early in definition. VIPs use is correlated with successful outcomes. IPA recognises a suite of *Asset VIPs*, *Facilities VIPs,* and *Subsurface VIPs* that, when used appropriately, play a significant role in E&P project definition.

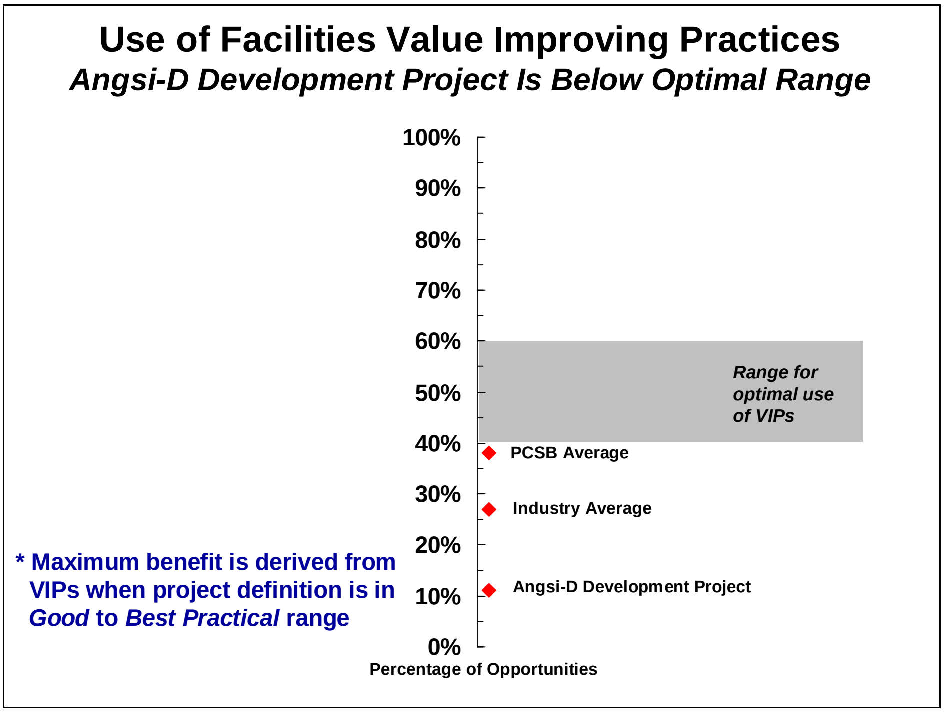


Figure 20

Figure 20 shows that the Facilities team used 11 percent of the Asset and Facilities VIPs applicable to the Angsi-D Development Project, which is below the industry average of 27 percent of VIPs use. Nine VIPs were applicable to the Angsi-D Development Project, and the team only used the 3D CAD VIP during FEED and detailed engineering. The subsurface team applied one out of six relevant Subsurface VIPs (SSVIPs), or 17 percent. The team used 3D visualization to analyse the reservoir.

Research has shown that the optimal use of Asset and Facilities VIPs is between 40 percent and 60 percent of the applicable VIPs. However, SSVIPs have little overlap, and therefore there is no maximum suggested use of SSVIPs. Refer to the Value Improving Practices appendix for the full definition of each VIP.

EXECUTION DISCIPLINE

The measurement of execution discipline is complex. IPA focuses on a simple set of execution discipline metrics that are cost effective to collect, including project manager continuity, the Project Control Index (PCI), and major late changes.

PROJECT CONTROL INDEX

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 the project definition phase, project control supports the achievement of *Best Practical* FEL by establishing effective cost and schedule control baselines. During the execution phase, project control maintains cost and schedule discipline to ensure that planned outcomes are achieved. The benefits of good FEL can be significantly eroded by poor project control practices during execution.

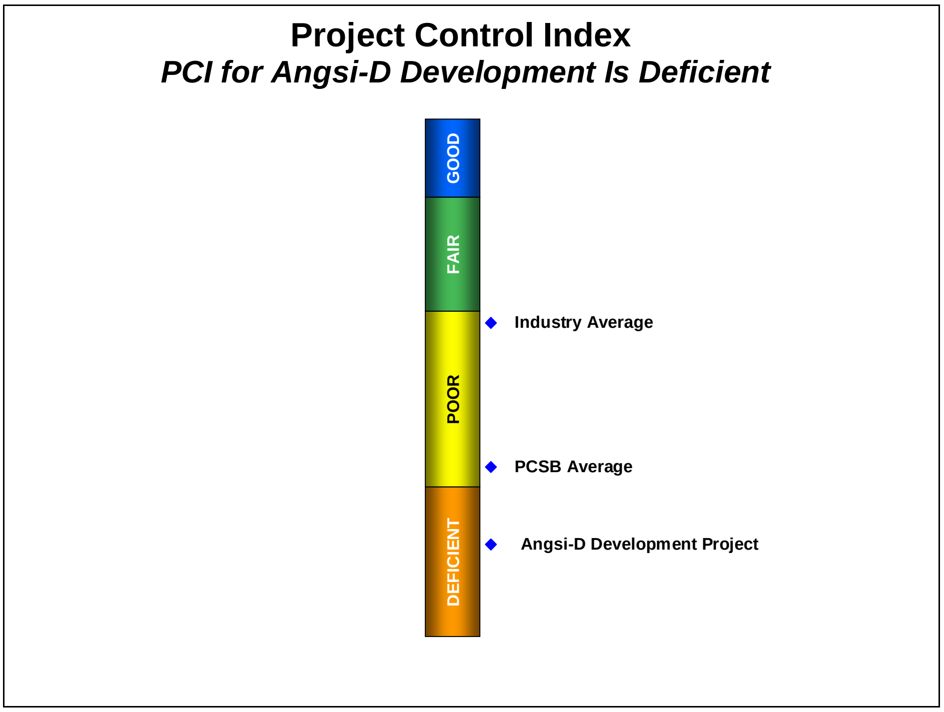


Figure 21

Figure 21 illustrates that the Angsi-D Development Project had a Project Control Index (PCI) in the *Deficient* range. The PCI includes two components: (1) estimating for control and (2) control during execution. Below we discuss the status of each component for the project:

- **Estimating for Control:** This element of the PCI measures how definitive project estimating methods were and how the estimate was validated. We found that the Angsi-D Development Project's estimating methods were based on quote information and on information from previous projects. The estimate did not provide any detail for all cost categories to support effective project control. The project estimate was not integrated with the project schedule. The estimate was not validated by an in-house estimating specialist using in-house or third-party metrics.

- **Control During Execution:** This element of the PCI measures the extent to which physical progressing was used, the extent of project status/progress reporting, and whether an owner project control specialist was assigned to the project during execution. The Angsi-D Development Project used physical progress during execution but did not use comprehensive methods. Project status reports were prepared on a monthly basis at a summary level. Not all elements of execution were covered in the report (e.g., engineering, fabrication, or installation). The reports highlighted some issues occurring during execution, not all activities were included. The schedule was presented in graph that includes the first level of activities and indicates some milestone. An owner project control specialist was not assigned to the project during execution. The project team does have dedicated staff to monitor and develop reports; however, these staff members are not qualified as project controllers.

The project team did not achieve a *Good* PCI because the estimate was not validated by an in-house estimating specialist, there was lack of cost detail for control, infrequent project status reporting, and lack of an owner project control specialist on the project team.

PROJECT MANAGER TURNOVER

The project team did not have project manager turnover in execution. However, the project suffered from turnover in several disciplines, namely the Facilities Manager, Drilling Lead, and Project Controller. PCSB had various ongoing projects in the area and reassigned team members to those projects. It is also fairly typical for small projects to develop young and inexperienced engineers, which was the case for Angsi D. These turnovers affected the continuity of execution because new members had to be brought up-to-speed with this fast-tracked project. The project manager continuity lessened the effect of the high attrition on the team. The facilities and wells design, as explained previously, were not complicated and PCSB has vast experience in the region.

MAJOR LATE CHANGES

The Angsi-D Development Project experienced major late changes in the well design and minimal changes for facilities. To date, all PCSB projects had major late changes and the industry average is 64 percent.

IPA measures as a major late change any change that take places 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. Included in our definition of late changes are any modifications to the engineering, design, equipment, or project execution plan necessary to meet the original objectives of the project. Excluded are changes to the project’s original scope and changes driven by external factors such as weather or strikes. Moreover, IPA does not consider either cost trending or rework, which are often captured in project change logs, as project changes.

CONCLUSIONS AND LESSONS LEARNED

In this section, we present the overall conclusions of the analysis including the project driver metrics, execution phase practices, and project outcomes. We also present lessons learned.

CONCLUSIONS

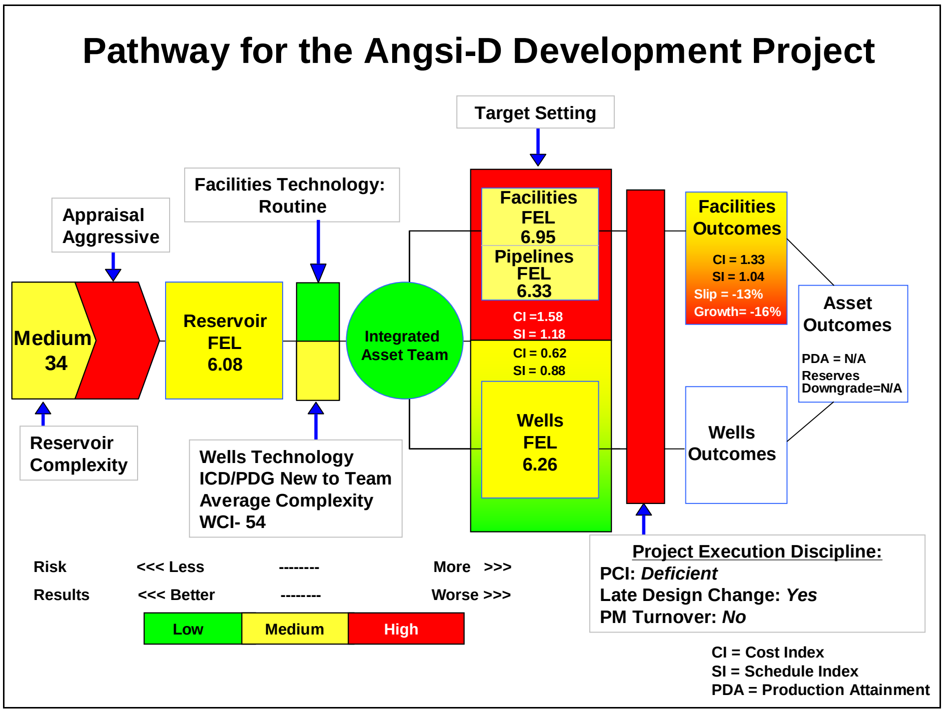


Figure 22

IPA assessed the Angsi-D Development Project drivers and the preparation achieved by the project team at sanction. The drivers are related to the project outcomes through the Pathway to Success, shown in Figure 1. The Angsi-D Development is a field with a fast-tracked schedule mandated by management. The project team faced four challenges in execution: schedule pressure to achieve first oil, lack of basic data from the aggressive appraisal strategy, high attrition rate of team members, and the lack of a project control specialist on the project team.

The facilities scope achieved industry average definition at sanction. The designs were standardised from a previous Angsi project to minimise risks from the schedule pressures and the inexperienced project team. The facilities cost was more expensive than industry average based on weight and water depth. The project had a normalised cost underrun, which was realised through negotiations with contractors post board approval of the estimate.

The execution duration was industry average but faster than the target duration. Because the project team was unable to secure a rig in time, first oil was late by 5 months, which eroded fast track efforts. Despite the routine facilities technology, adopting a similar platform design from previous phases, and performing detailed engineering prior to project sanction, the project team's cost and schedule estimate was too conservative resulting in an expensive facility. The poor facilities outcomes are also attributed to the lack of control over the installation vessels and rig.

LESSONS LEARNED

Based on our analysis of historical industry performance and our assessment of the Angsi-D Development Project, we present the following key lessons for future projects.

1. *Using previous Angsi design helped schedule performance*. The AnDP-D platform was based on the Angsi-B WHP design. The team modified the existing design to suit the seabed strength and drilling rig requirements. This approach was much faster than starting the AnDP-D design from scratch, and was especially helpful given the project's time constraints.

2. *Completing subsurface studies before engineering definition reduces late changes.* The Angsi-D Development Project began engineering before key subsurface study results were available to support and finalise the well construction scope. The project team suffered from several well design changes as a result. Historically, projects that obtained all basic data before entering the Define phase achieved their business objectives more often than did projects that lacked timely basic data. Providing basic subsurface data early improves operability and production attainment.

3. *Continuity in key discipline positions helps achieve predictable project outcomes*. The Angsi-D Development Project suffered a high number of key team member turnovers. Project team turnovers are detrimental to the execution schedule and erode predictability of project outcomes. Turnover of key team members should be avoided. If turnover is unavoidable, Petronas should give proper attention to retention, succession, and transition plans to ensure an adequate and timely handover of project activities and responsibilities, including the communication of issues that have already been resolved.

4. *Good project execution planning is key to project success.* The project execution plan (PEP) is a key document in any project and serves as the basis for the project team to effectively progress into each phase. Although the Angsi-D Development Project was not complicated in terms of technology, it was schedule and resource constrained. The weak PEP, led by a weak schedule, hindered the project team's efforts to respond to the constraints.

5. *Estimate validation helps to achieve cost competitiveness.* The project controls for the Angsi-D Development Project were *Deficient*. The lack of estimate validation contributed to the high costs compared with Industry for similar WHP and pipelines. The facilities scope underran, and the cost estimates could have been significantly more accurate if they had been validated by an in-house estimating group. Given the lack of team control in the installation vessel and rig rates, project teams for upcoming projects should be vigilant in comparing recently completed projects to ensure the vessel and rig rates are in line with industry averages.

APPENDIX A: COST BENCHMARK ANALYSIS

The UCEC charts below illustrate the platform benchmarks explained in the report.

PLATFORM JACKET WEIGHT ANALYSIS

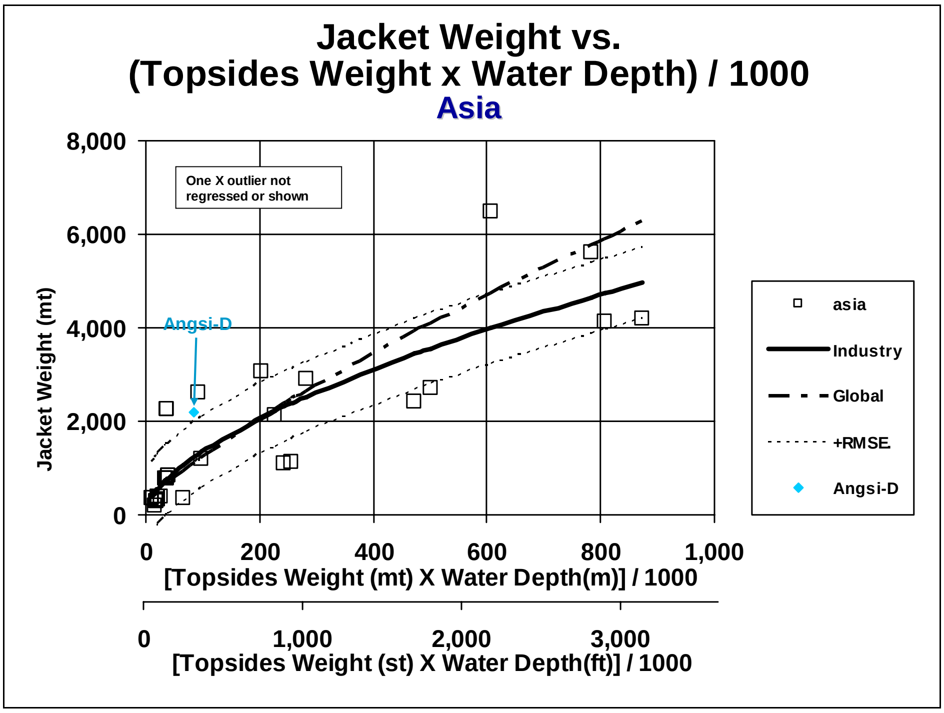


Figure 23

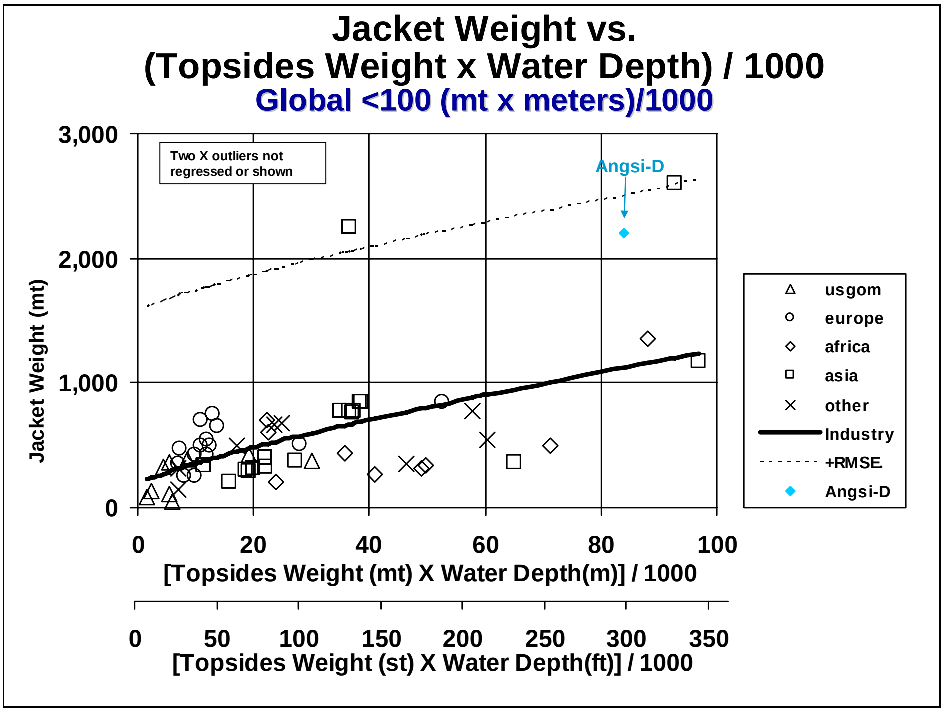


Figure 24

PLATFORM JACKET COST ANALYSIS

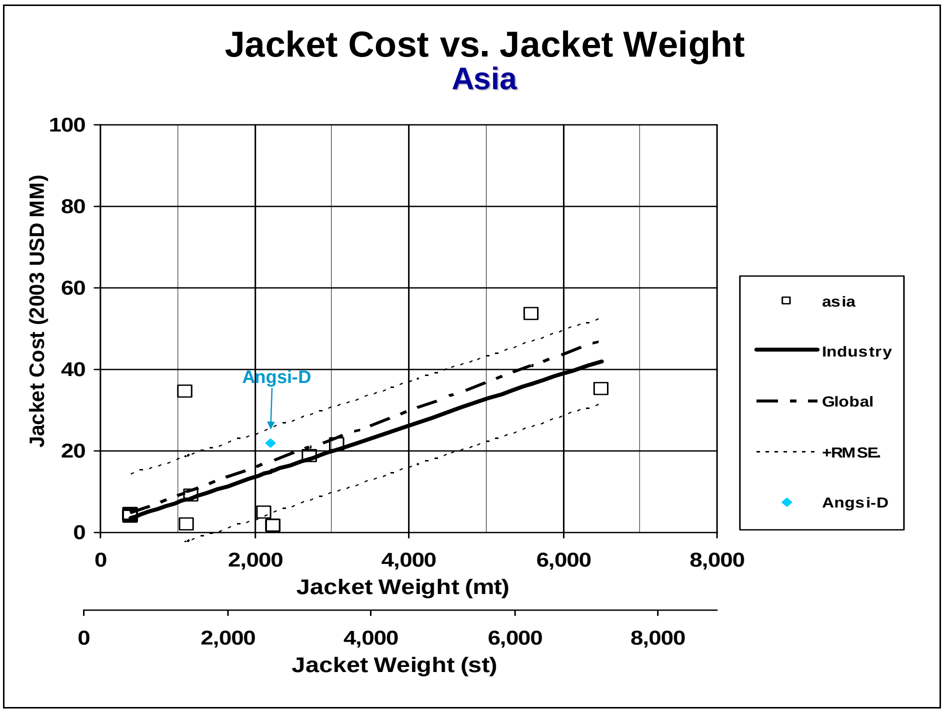


Figure 25

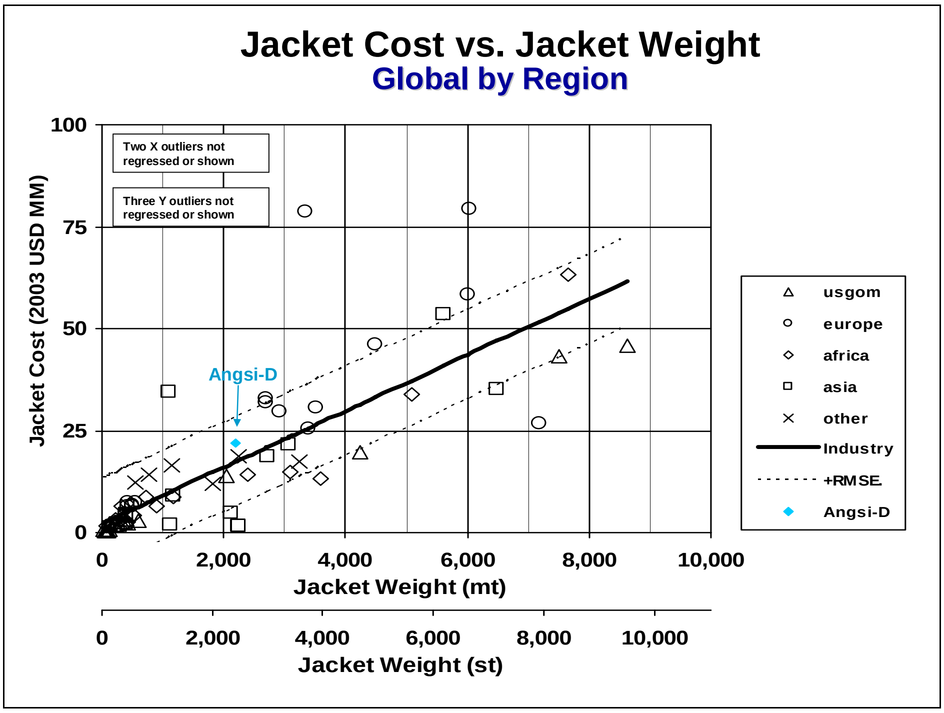


Figure 26

PLATFORM TOPSIDE COST ANALYSIS

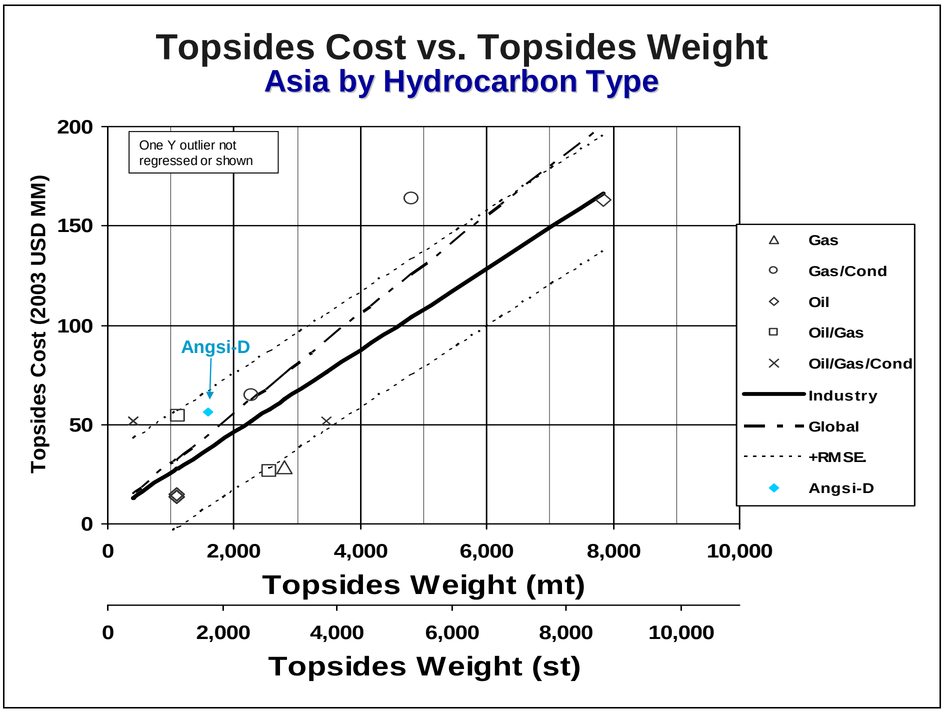


Figure 27

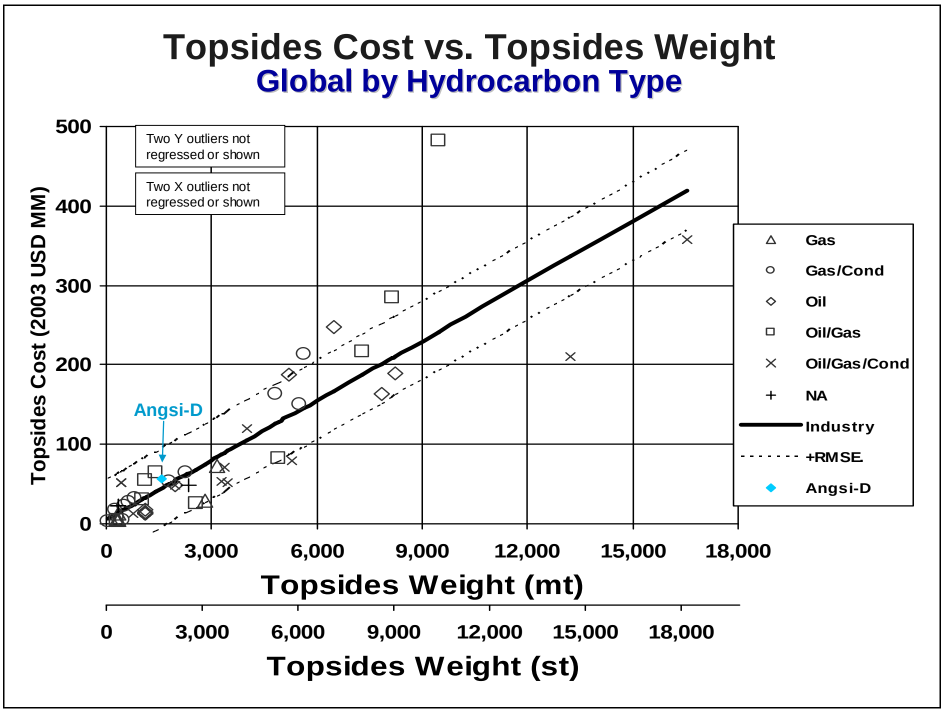


Figure 28

APPENDIX B: TEAM TURNOVER RESEARCH

Establishing an adequately staffed and integrated project team during FEL is a major foundation for successful project outcomes. However, it is equally important to maintain team continuity during execution to avoid undermining the foundation laid by solid FEL. Project manager turnover, for instance, results in longer and less predictable execution schedules and in lower operational performance. As shown in Figure 29, research[31] has also shown that a turnover of other key project team members erodes project outcome performance. The results of this research resonate clearly with the Angsi-D Development Project.

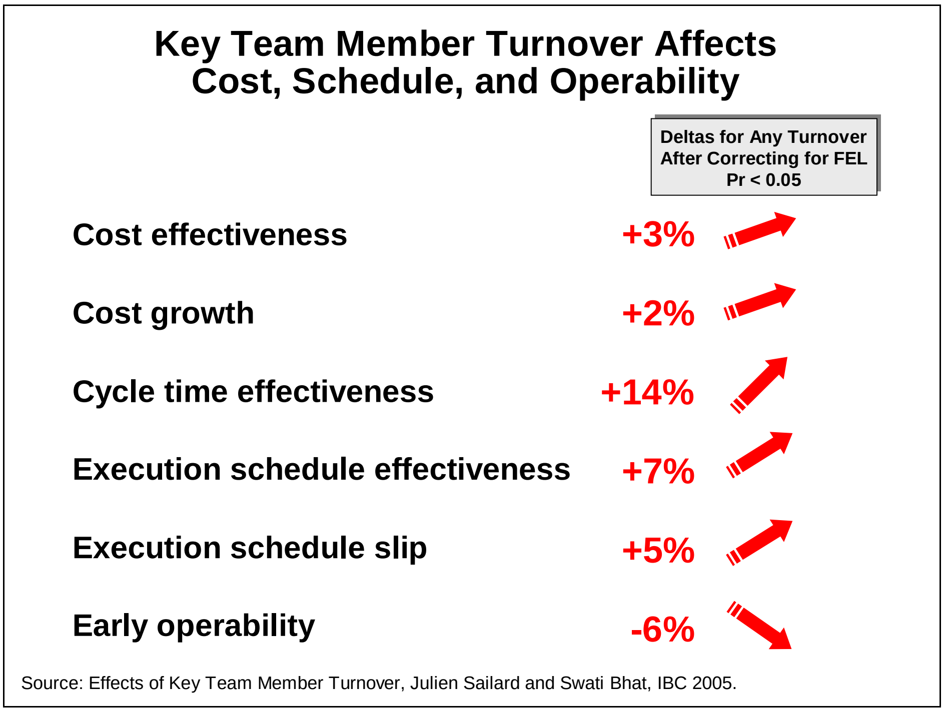


Figure 29

Among the most common reasons for turnover are reassignments of resources within the company, promotions to a new position, retirement, or individuals leaving the company.

The most common source of team turnover is the reassignment of resources from one project to another, which is driven by business decisions. The project team should be prepared to educate business sponsors on the detrimental effects that any core team turnover can have on the project if business sponsors are not already aware of the risks. Business sponsors, on the other hand, need to evaluate very carefully whether the benefits of reassigning a key team member to another project or position truly outweigh the increased risk to the cost and schedule. The project should also develop and establish a transition plan to mitigate the effect of turnovers.

[31] Julien Saillard and Swati Bhat, *Effects of Key Team Member Turnover*, IPA, IBC 2005.

APPENDIX C: THE CONTEXT OF UPSTREAM BENCHMARKING

Developing an asset from exploration discovery to production is a complex process involving, in effect, three projects executed by several different functional areas that must be coordinated. At a basic level, developing an asset requires the execution of a (1) reservoir evaluation project, (2) development drilling project, and (3) facilities construction project. Achieving excellence on any one of these complex projects in isolation is a challenge. Achieving excellence in asset performance requires individual project excellence as well as excellence in multiproject integration and cross-functional coordination.

IPA has developed a suite of ***benchmarking metrics*** to help its clients understand project outcomes and the drivers of those outcomes. The suite includes metrics for the project at the asset level, for the various disciplines whose combined efforts combine to deliver the project, and for the physical components that make up the asset.

PROJECT "GIVENS"

The location and subsurface conditions are out of the control of the project team. Some of these givens are directly measurable, such as water depth. For others, IPA has developed special metrics, including ***Reservoir Complexity*** and ***Well Complexity***. These two independent metrics comprise assessment of many factors to provide an expression of project complexity.

The components of the Reservoir Complexity encompass structural and stratigraphic complexity, rock and fluid quality, and reservoir drive energy. The Well Complexity considers subsurface hazards, reservoir interfaces, well geometry, equipment required, and the operational environment.

ASSET DEVELOPMENT PRACTICES

IPA has identified ***Appraisal Philosophy*** as a factor affecting both project drivers and project outcomes. It can be argued that the choice of this strategy is within the control of the operator. However, in practice it is often driven by circumstances, including water depth, government or schedule pressure, and fundamental economics. The team performing execution usually has to deal with an appraisal strategy that has been provided to it.

Competitive targets are necessary to achieve competitive project performance. Targets should be reasonably aggressive and should be based on data and adequate definition. Often, we observe schedule targets driven by calendars and cost estimates driven by a need to "improve" project economics.

Upstream asset developments are complex undertakings that require fully developed teams and well understood work processes to yield consistent results. Frequently, we observe highly complex developments being undertaken in an *ad hoc* fashion. When we observe all the disciplines of a project team working together in a structured framework, we credit the project for ***Team Integration***.

DRIVER METRICS

Front-End Loading (FEL) is IPA's primary driver metric. It is a measure of the level of definition of a project. Usually FEL is measured at the time of project sanction, so IPA can provide benchmarks of project performance against industry average and the range of *Best Practical* FEL, which differs for each FEL Index. *Best Practical* is derived from the database. It comprises the optimal level of project definition for adequately reducing risk and uncertainty, constraining cost and value estimates, without over-commitment of funds and erosion of project value. It can be useful to measure FEL at earlier stages in project definition, when analysis of the gaps to *Best Practical* can be helpful in planning the activities leading up to sanction.

There are four FEL metrics for upstream projects. The three specific discipline metrics are ***Reservoir FEL***, ***Well Construction FEL,*** and ***Facilities FEL***. The fourth metric, ***Asset FEL***, a combination of the three discipline FEL metrics, is used to benchmark the whole asset.

Value Improving Practices (VIPs) are disciplined practices that tend to improve the value of capital projects in the process industries. Certain VIPs are more suited to particular disciplines, although our research has shown benefit from applying the others comprehensively across the whole asset.

Successful VIPs application requires a formal, disciplined, and documented approach with measurable results. For VIPs to have a positive effect on project outcomes, the project must achieve an advanced level of project definition. Implementing VIPs with below average FEL effectively eliminates the benefits of their use; when FEL is incomplete, project changes that occur as definition continues alter the basis of the project, thereby eroding the benefits of having used the VIP.

IPA research has revealed the statistical significance of all of the above driver metrics in affecting project outcomes.

EXECUTION DISCIPLINE METRICS

The measurement of execution discipline is complex. IPA focuses on a simple set of execution discipline metrics, which are cost effective to collect, including ***project manager continuity, the Project Control Index (PCI),*** and ***late design changes***.

Other elements of execution discipline can be captured through a "lessons learned" process. IPA routinely conducts ***Lessons Learned Workshops*** in conjunction with closeout interviews to help teams identify practices to apply to future projects—the real transferable lessons learned.

OUTCOME METRICS

IPA has developed a comprehensive set of models that allow a top-down analysis of project costs and schedules. The costs include project definition, project management, engineering, materials, installation, and commissioning.

The highest level cost benchmark is based on ***capital cost per barrel*** for facilities and drilling. The models compare the project with the industry average capital expenditure per barrel of oil equivalent ($/BOE).

The next level looks at a ***facilities program cost*** (concept unspecific), i.e., a benchmark of the total non-export facility costs. To compare projects consistently, export costs are always excluded from this metric.

On a more detailed level, we benchmark the cost of ***individual project components***, such as platforms and pipelines.

We assess the ***contingency*** required for the facilities as a percentage of the base estimate.

We analyse the project's overall ***schedule*** performance.

Predictability of project outcomes is also important, so IPA measures both ***cost and schedule predictability***, as ratios of the outcomes to planned targets.

OPERABILITY/PRODUCTION ATTAINMENT METRICS

Completing a project predictably fast at low cost will not benefit the business unless it operates satisfactorily, and anticipated value is realised.

IPA evaluates the degree to which life-of-project production stream estimates change during the execution and early production stages of the project, as further reservoir evaluation and early reservoir management change the perception of the reservoir. The drawback with this measure is that the ultimate production stream not known until the end of field life. Furthermore, production stream re-estimation is a time-consuming process. Therefore, often teams do not undertake such an exercise from project sanction until sufficient dynamic reservoir performance data have been gathered, which is often months or even years into field life.

As a more tangible proxy for field performance, IPA now puts more emphasis on ***production attainment***, the ratio of actual production in the second 6 months of operation (to allow for a settling in period and adjusted for schedule slips) compared to the production profile planned at sanction.

We also monitor the incidence of ***operability problems*** in the first year that required extensive unplanned shutdowns or capital investment to rectify.

APPENDIX D: FRONT-END LOADING INDEX

Front-End Loading (FEL) is a process by which a company translates its commercial reservoirs into capital projects. The objective of FEL is to gain a detailed understanding of the project to minimise the number of changes during later phases of project execution. FEL proceeds until the "right" project is selected and is not finished until a full plan of development and design-basis package has been completed. FEL as a concept includes reservoir evaluation, and project and well definition and design.

IPA has developed FEL Indices to consistently measure the level of definition achieved during FEL. For upstream projects, IPA has developed three discipline FEL Indices, for (1) Reservoir, (2) Well Construction and (3) Facilities; and a composite Asset FEL Index. All FEL Indices have a scale from 3.00 to 12.00, with 3.00 representing the most advanced level of definition and 12.00 representing just a sketchy outline of project intent with no formal definition work done. (For illustrative purposes, the scale is often truncated at 9.00 in IPA reports and presentations.)

To achieve the extreme FEL rating of 3.00, a team would have to ensure that all FEL components are completed to a *Definitive* level, including reservoir appraisal, well and facility engineering, and regulatory requirements, which requires that all permits are in hand. However, at the time of sanction, such goals are neither realistic nor necessary. Consequently, for each FEL Index, IPA has identified the range of *Best Practical* values at sanction. For example, engineering would be only 10 to 30 percent completed—with good participation and buy-in of all team members—and the team would have identified all environmental issues and applied for the required permits, but not necessarily received the permits. Therefore, the goal of all project teams at the time of sanction should be to achieve a *Best Practical* FEL status, rather than 3.00.

Each of the three upstream discipline FEL Indices has four components: (1) quality and uncertainty of available data; (2) factors external to the project team such as regulations and company rules; (3) technical deliverables, including the buy-in of all stakeholders; and (4) plans for later phases.

The weighting of the factors in each FEL Index has been determined from the database to reflect the observed relative importance of the factors. The weightings are specific to each FEL index.

RESERVOIR FEL

The four components of Reservoir FEL are (1) Inputs, (2) Constraints, (3) Tasks and (4) Reservoir Evaluation Execution Planning. These are explained below.

Inputs

This component covers the comprehensiveness and quality of data available for reservoir evaluation, including seismic, logs, core and SCAL, fluid data (PVT analysis, impurities, composition, geochemistry), reservoir pressure, well tests and/or production history, and production analogs. Ratings are (1) *Screening*: Data not collected or not available for analysis; (2) *Assumed*: Poor quality data or from less than one-third of the field, or values adopted from close analog fields; (3) *Preliminary*: Good quality data or from less than two-thirds of the field; and (4) *Definitive*: no further data required.

Constraints

This factor identifies and determines the effect of any issues that prevent a thorough reservoir evaluation or that restrict production, and the level of preparedness to overcome these issues. These issues can include: regulatory and environmental; license terms and requirements; timing and budget limitations; appraisal philosophy; business and commercial strategy; company-induced operating constraints; technology to be employed (wells and/or facilities); risk tolerance; and joint operating agreement or partner or unitisation issues. For a *Best Practical* level, the team will have been identified all issues relevant to the project, and have put in place plans to mitigate the risks.

Tasks

The Tasks component of Reservoir FEL comprises the status of the analysis, modelling, and interpretation of the input data. Such work includes seismic interpretation; geologic mapping and rock properties analysis; fluid analysis and characterisation; the building of geologic and reservoir simulation models; confirmation of the drive mechanism and extent of reservoir compartmentalisation; development drilling plan; production profile and life-of-project production stream estimates; and risk and uncertainty analysis.

Reservoir Evaluation Execution Planning

This factor assesses the state of readiness of execution plans in three areas:

1. Team Interaction – Covers team formation, roles and responsibilities, shared objectives, uncertainties and tasks, reservoir evaluation activity schedule, and full project schedule development/integration.
2. Plans and Documents – Assesses the level of detail in various plans (e.g., reservoir surveillance plan), including the facilities design basis memorandum (reservoir and fluid property definitions for facility design), an integrated reservoir management plan, the plan for data acquisition during development drilling, the field depletion plan/development plan, and the reservoir surveillance plan.
3. Controls – Covers commercial agreements, management of change procedures, accountability of the reservoir management team, and the reservoir management plan risk mitigation.

WELL CONSTRUCTION FEL

The four components of Well Construction FEL are (1) Scope of Work, (2) Regulatory/Health Safety and Environment, (3) Well Engineering, and (4) Well Project Execution Planning and Scheduling.

Scope of Work

The Scope of Work component of Well Construction FEL considers the interaction of drilling with the reservoir and facilities teams, as well as the degree to which local conditions are known. To a large extent, the Scope of Work reflects the external conditions that the well program must encompass. Factors considered include definition and consensus on the well objectives and on overall program objectives and timing; analysis of the relevant weather and environmental conditions; statement of the requirements of the reservoir depletion plan; completions needs and any stimulation requirements; plans for data acquisition during development drilling and production; and plans for how the well will be operated.

Regulatory/Health, Safety, and Environment

This FEL component considers the status of regulatory permitting, health, safety, and environmental plans, including plans for conducting HAZOP reviews and drilling waste disposal. Progress on this component, more so than on any other, depends heavily on the duration remaining before development well spud.

Well Engineering

The Engineering component considers progress on "traditional" well and completion design activities. Aspects such as the certainty of surface locations and bottomhole targets, the analysis of shallow hazards, fracture gradient and pore pressure data, the equipment specifications, and the well design fall into this component of Well Construction FEL. The design should be reviewed by stakeholders and subject to peer reviews.

Well Project Execution Planning/Scheduling

Execution Planning considers the state of readiness of the execution plans. The most critical aspect, particularly for offshore operations, is whether a drilling rig has been selected. The daily rig rate is the highest single contributing factor to well cost uncertainty. Other aspects considered include assignment of team members with roles and responsibilities; demonstration of an appropriate contracting strategy for rig; equipment and third-party services; operations issues (simultaneous operational interfaces, relief well plans, well control, hurricane evacuation procedures); and cost estimates with contingency or probabilistic analysis.

Scheduling looks at the process of ensuring that everything needed is in place for the wells to be spudded on the planned date. Issues such as identifying all major tasks, obtaining funding for all major equipment and long-lead items, ensuring adequate manpower staffing requirements, and networking with other disciplines are considered.

FACILITIES FEL

The four components of Facilities FEL are (1) Fluid Characterisation and Volumes, (2) Project-Specific Factors, (3) Engineering Status, and (4) Project Execution Planning.

Fluid Characterisation and Volumes

This component of Facilities FEL assesses whether the project team (1) obtained representative samples and (2) fully characterised the fluids for problematic constituents. The project team needs specific aspects of the reservoir depletion plan in order to design appropriate facilities. This includes, but is not limited to, flow rates and composition for each fluid, fluid temperature and pressure at the wellhead, and sanding potential. The extent to which the reservoir uncertainties are communicated to the facilities team members is also important. IPA looks for a completed design basis to be issued at, or near the start of, the FEED phase.

Project-Specific Factors

This category comprises a group of 13 project characteristics, or factors, of the project site and its location or region. These factors take into account the physical site, various political and community issues, HSE, and other factors that should be addressed in FEL.

Project-specific factors are:

- Soils and Surveying Data
- Permits
- Concession/Lease Requirements
- Local Import/Export Requirements
- Community Relations
- Security
- Offshore POB
- Remote Support and Logistics
- Local Content
- Local Labour Availability
- HSE for Facility Ops
- HSE for Fab, Transport and Install
- Yard Availability

Engineering Status

Engineering status is characterised by the level of total engineering completed **plus** the amount of owner/operator input into the design. Typically, 15 percent to 30 percent of the design has been completed for projects that are rated *Advanced Study*. Less engineering (approximately 1 to 5 percent) has been completed for projects that are categorised as a *Limited Study*. The other major distinction between the *Advanced Study* and *Limited Study* ratings is whether the owner/operator provided extensive input into the design at the time of estimate preparation. If the owner/operator did not contribute to the design, then the potential for design changes is increased. Design changes lead to cost growth, schedule slip, and operational performance reductions. The *Screening Study* rating is assigned to projects for which the facilities technology has not yet been selected. The engineering status is considered *Full Design Specification* when 40 percent to 100 percent of the engineering has been completed. Rarely is the engineering that extensive—nor should it be—for a project at sanction.

Engineering should include soils and hydrology (soil integrity, including contamination, load-bearing capacity, and the presence of obstructions), plot plans (unit configurations, layout of equipment, large-bore piping and one-line drawings for smaller bore piping). For projects involving modifications to existing facilities, the quality of the as-built drawings and the information about the integrity of the structure and tie-in points are critical.

Project Execution Planning

Project execution planning in Facilities FEL encompasses three separate but related items:

1. Composition of the full project team, including the assignment and understanding of roles and responsibilities
2. Details of the planned contracting strategy for the project
3. Development of a detailed and integrated project schedule that incorporates the interfaces, effects of equipment delivery dates, interferences, and resource loading, drilling, hookup and commissioning sequences for startup

If all of these items have been completed, then the project execution planning factor is rated *Definitive*, which is *Best Practical*. If the schedule includes only major tasks but identifies the critical path and its components, then the factor is rated *Preliminary*. If only major milestones are scheduled, usually based on historical factors, the project execution plan is rated *Assumed/Factored*. If a schedule has not been developed and neither a project team nor a contracting strategy has been selected, then the project execution plan is rated *Not Used*.

ASSET FEL

IPA has developed component FEL Indices for reservoir, wells, and facilities, as explained above. IPA's research on overall asset outcomes has shown that a combined index—the Asset FEL Index—is strongly correlated with overall asset performance. The correlation is strongest when the component FEL Indices are combined in the ratio 2:1:2. Thus, the Asset FEL is calculated as the sum of 40 percent Reservoir FEL, 20 percent Wells FEL, and 40 percent Facilities FEL.

APPENDIX E: TEAM DEVELOPMENT INDEX

The Team Development Index (TDI) measures the processes that enhance team performance, improve the level of project definition, increase the use of Value Improving Practices (VIPs), and drive project outcomes. Strong team development supports the achievement of *Best Practical* levels of Front-End Loading (FEL), which IPA's statistical analysis has identified as the most powerful influence on project outcomes. It is virtually impossible for projects with substandard levels of team development to achieve excellent project definition. Strong team development also supports the selection and implementation of VIPs. VIPs' use, combined with strong FEL, further drives positive project results. Moreover, IPA research presented at the Industry Benchmarking Consortium of 2001 (IBC 2001) shows that team development drives safety results, cost performance, execution schedules, and operational performance more than other key drivers of project outcomes.[32] In other words, when FEL levels are poor, good team development improves project outcomes. When FEL levels are average, good team development drives better project outcomes than average or poor levels of team development.

The TDI is composed of the following four equally weighted factors:

- **Project Objectives:** This factor of the TDI measures whether specific project objectives have been developed and translated from the business objectives, which were developed at the end of the business appraisal stage of FEL (FEL 1). This factor also measures whether these objectives have been communicated to and are understood by all members of the project team.
- **Team Composition:** This factor of the TDI measures whether all functions that can influence the project's outcomes are represented on the project team and whether the team is adequately staffed.
- **Roles and Responsibilities:** This factor of the TDI measures whether roles for team members have been defined, responsibilities have been identified, expectations have been established, and tasks have been outlined and assigned. This component examines whether these responsibilities and tasks have been agreed to and whether the team is aligned. This element also assesses whether problem areas have been identified and, if identified, whether responsibility for developing mitigation or problem resolution plans has been assigned.
- **Project Implementation Process:** This factor of the TDI measures whether a common work process is in place for developing and executing the project. It also measures whether this process is used on all company projects and whether this process is understood by the project team.

TDI ratings are *Good, Fair, Poor,* and *Undeveloped*. A *Good* rating indicates that all the factors of the index are in place. A *Fair* rating indicates that at least one of these four factors is not yet complete. A *Poor* rating indicates that one or more of these factors is missing. An *Undeveloped* rating indicates that a project team is not in place.

[32] *Enhancing Team Effectiveness to Improve Project Outcomes*, IBC 2001.

APPENDIX F: VALUE IMPROVING PRACTICES

APPLICATION AND MEASUREMENT OF VIPS

Each of the Value Improving Practices (VIPs) is defined below. However, these definitions do not explain the requirements for successful VIPs application. Successful VIPs application requires a formal, disciplined, and documented approach with measurable results:

- *The VIP activities must be scheduled and resourced early during a project's life cycle* for these practices to have their maximum effect on project costs. Moreover, resources must be set aside so that the practices may be satisfactorily implemented, perhaps even using individuals external to the project to oversee the application.
- *The VIP activities must be done thoroughly*. For example, ensuring that a project employs the best available technology—the goal of the Technology Selection VIP—requires identification of potential candidates through rigorous patent searches, visits to university research centers and process licensors, and the subsequent evaluation of these candidates. Thorough application of this VIP means that the potential candidates cannot be limited to only those of whom the firm is currently aware.
- *The VIP must be applied to the full scope of the project* (at least initially). Arbitrarily limiting the scope to a portion of the project unnecessarily limits the practices' potential effects.
- *Guidelines must exist to ensure that each VIP is applied consistently,* i.e., which costs should be evaluated (e.g., total life cycle cost) and which economic and financial assumptions should be used.
- *The results of VIPs application must be documented.* Documentation is performed to provide a basis for the project team to evaluate the cost effectiveness of the practice and to provide lessons learned for future project teams. At a minimum, the following information should be recorded: a description of the activity, the monetary value of the scope work reviewed, the monetary savings achieved, and the cost of applying each VIP.

VALUE IMPROVING PRACTICES DEFINED

Technology Review and Selection	A formal, multidisciplinary team process that searches and screens alternative technologies to identify opportunities that may yield a significant competitive advantage. This process involves both internal and external reviews of reservoir, drilling, completion and facilities technology that may range from research concepts to emerging or fully proven technology.
Flow Assurance & Reliability Modelling	A methodology intended to increase value by providing an objective analysis of the production reliability, capacity alignment, and uncertainties surrounding the production stream. The relationships of all components in the system are analysed beginning with the static reservoir pressure through to the separator.
Process Simplification	A disciplined analytical method for reducing investment costs—and often operating costs as well—by either combining or making unnecessary one or more chemical or physical processing steps.
Predictive Maintenance	An approach to maintaining a facility whereby equipment is monitored and repairs are made before failure. Typically, this approach requires adding various measurement devices to evaluate operating characteristics.
Customised Standards and Specifications	An evaluation of the needs of a specific facility before it is designed. Engineering standards and specifications can affect manufacturing efficiency, product quality, operating costs, and employee safety. However, the application of codes, standards, and specifications sometimes exceeds the facility's needs and unnecessarily increases cost.

Design-to-Capacity	An evaluation of the maximum capacity of each major piece of equipment. Often equipment is designed with a “safety factor” to enable catch-up capacity to be added if production needs to be increased.
Classes of Facility Quality	An analysis that establishes the necessary quality of the facility to meet business goals. This VIP evaluates reliability, expandability, use of automation, life of the facility, expected stream factor, likelihood of expansion, production rate changes with time, product quality, and product flexibility. The Classes of Facility Quality VIP can be used to determine needed design allowances, redundancy, sparing philosophy, and room for expansion.
Value Engineering	A disciplined method used during design, requiring the use of a trained Value Engineering consultant—usually from outside the project team—aimed at eliminating or modifying items that do not contribute to meeting business needs.
Constructability Reviews	An analysis of the design, usually performed by experienced construction managers, to reduce costs or save time during the construction phase. To be considered a VIP rather than just a good project practice, Constructability Reviews must begin during FEL and be repeated through construction.
Energy Optimisation	A simulation methodology for optimising the life cycle costs by examining power and heating requirements for a particular process. The objective is to maximise the total return by selecting the most economical methods of heat and power recovery.
Waste Minimisation	A disciplined approach used during design to minimise the production of waste products. This VIP might result in the addition of equipment or examination of alternate process technologies that have a lower amount of waste sidestreams.
3D CAD	The use of three-dimensional computer-aided design (3D CAD) during Front-End Loading and detailed engineering. The objective is to generate computer models of the project to reduce the frequency of dimensional errors and spatial conflicts that create the need for design changes during construction. The use of 3D CAD also improves visualisation of the facility, which increases the quality of Operations’ input and training. To be considered a VIP rather than just a good project practice, 3D CAD must be used during FEL as well as detailed engineering.
Risk and Uncertainty Analysis (RUA)	A formal structured process following standardised procedures, often facilitated at strategic points. The process should quantify the impact of risk and uncertainty on business objectives and provide a plan to mitigate against the identified risks and uncertainties. To ensure consistency, the process must incorporate experts outside the team versed in risk assessment and technical uncertainties. The decision to use internal versus external technical resources depends on the size and complexity of the project.
Full Cycle Depletion Plan	A plan for producing hydrocarbons through the full life of the field, from present to abandonment. The development plan (number of wells, reserves, production, cost and benefits, etc.) and alternatives reviewed are qualified and documented. An important element is the information collection on which management decisions depend. The analysis involves assigning risks and integrating reservoir, wells, processing facilities, export, health, safety, and environmental management.
Well Definition and Design	A systematic set of activities led by a facilitator to clearly define development wells in a way that is aligned with the company’s strategic business objectives and depletion plan. This practice should establish the optimal technical basis of well and completion design. It employs reservoir characterisation and other relevant subsurface data in conjunction with safety, health and environmental effects, development concept, expected asset life, applicable regulations and standards, and operation environment.
3D Visualisation	A practice in which all subsurface groups, Geology and Geophysics, Reservoir Engineering, and Drilling and Completions, share a 3D earth model and interpretation. The shared earth model is used to perform geologic evaluation of the reservoir and field, 3D simulation of the reservoir, depletion planning, and well bore planning. An interactive visualisation center may be used to enhance this process, but is not essential.

APPENDIX G: UPSTREAM FACILITIES PROJECT CONTROL INDEX

The Project Control Index (PCI) measures the set of practices by which a project team manages (or plans to manage) cost and schedule performance during the Front-End Loading (FEL) and execution phases of a project. The objective of project control is to establish and maintain a disciplined approach to managing work activities during execution so that planned project outcomes are achieved. Project control is a process whereby effective cost and schedule performance baseline plans are established (planning, estimating, and scheduling), measurements of performance against the plan are made and evaluated (progressing and forecasting), and corrective action is taken (change management) when measures indicate a deviation from the plan is occurring or is likely to occur.

During FEL, project control focuses on establishing a cost estimate and schedule that are suitable not only as a basis for project decisions, but also as a basis for control of project activities. A strong control basis supports the achievement of *Best Practical* FEL. During project execution, project control focuses on measurement and reporting of progress, forecasting, and change management. The PCI quantifies the strength of the planned or actual practices. In a postsanction or closeout analysis, measures of the actual practices used during execution are substituted for what was planned during FEL. Planning without follow-through during execution will not result in the project outcomes desired. Table 25 shows the components of the PCI for closeout analyses.

Table 25
Components of the Project Control Index for Closeout Analyses

PCI Component	Elements of Project Control
Estimating for Control	Estimating and Scheduling Methodology • Definiteness of estimating methods (including contingency estimate) • Level of detail for each cost category (including owner costs) • Degree of cost and schedule integration • Consistency with latest design Estimate Validation and Review Process • Extent of estimate review and quantitative validation • Owner cost knowledge brought to review and validation practices
Control During Execution	Measurement of Progress • Extent that physical progressing was performed • Level of detail of measurements for each cost category Reporting of Progress and Status • Frequency that project progress and status were reported • Level of detail of progress reporting for each cost category Owner Participation in Project Control • Owner control specialist's responsibilities were defined • Level of involvement of owner project control specialists Collection of Cost and Schedule Data at Closeout • Extent and level of detail of historical database to support planning

The PCI is rated at four levels: *Good, Fair, Poor,* and *Deficient*. A *Good* rating indicates that all of the elements for effective project control are in place or were used with fairly robust methods, detail, and so on. A *Fair* rating indicates that one or more of the elements is not in place or was not used, or that the methods and detail employed were not robust. A *Poor* rating indicates that several of the elements for effective project control are missing or were not used. A *Deficient* rating indicates that elements for effective project control are not in place or were not used.

APPENDIX H: COST ADJUSTMENTS

All projects in the IPA database have estimates, and if applicable, actual cost data, in local currency money of the day. To compare any project with other similar projects in IPA's databases, we have to adjust all the costs to constant year United States (U.S.) dollars. The baseline year we currently use is 2003.

For actual costs, normalisation is done in the following steps: For each expenditure category, we apply a standard S-curve expenditure distribution, which yields expenditures for each month. Those monthly expenditures are converted from local currency to U.S. dollars at the prevailing exchange rate of the month. We then de-escalate the U.S. dollar amounts to the year 2003 on a cost category basis using escalation data.

For estimates, the normalisation is similar. We remove any escalation included in the estimate. We convert from local currency to U.S. dollars at the exchange rate prevailing at the time of the estimate. Finally, we de-escalate the U.S. dollar amounts to the year 2003 on a cost category basis using publicly available escalation data.

All IPA models, benchmarks, and statistical analyses are performed using constant 2003 U.S. dollars. From any result, in constant 2003 U.S. dollars, we generate an index being the ratio of project cost to the database benchmark:

$$\text{Index} = \frac{\text{Project Cost } ({}^{2003}\text{US\$})}{\text{Benchmark } ({}^{2003}\text{US\$})}$$

In our reports and presentations, however, we present our results in terms that are comparable to the local currency money of the day, either as spent or as estimated.

To generate the benchmarks in local currency money of the day, we divide the project figures by the relevant index:

$$\text{Benchmark (local currency money of the day)} =$$

$$= \frac{\text{Project Cost (local currency money of the day)}}{\text{Index } ({}^{2003}\text{US\$})}$$

$$= \frac{\text{Project Cost (Local currency money of the day)} \quad \text{X} \quad \text{Benchmark } ({}^{2003}\text{US\$})}{\text{Project Cost } ({}^{2003}\text{US\$})}$$

Because the above procedure effectively re-escalates and converts back to local currency, project teams can recognise the estimates and costs presented in our reports and presentations, and also make direct comparisons with the benchmarks in local currency money of the day.

We recognise that, with this methodology, short-term currency fluctuations can have a minor influence on benchmarks for projects that account in currencies other than the U.S. dollar.

APPENDIX I: OUTCOME METRICS METHODOLOGY

Note: Not all of these metrics may apply to your project.

COST PER BARREL OF OIL EQUIVALENT ($/BOE)

To assess the development costs, we compare the project's cost per barrel with that of other similarly sized fields. The advantage of the cost per barrel comparison is that it provides a consistent measure across all projects and provides a gauge for the cost effectiveness of a company in developing a field. It also provides a useful reflection on the quality of the asset development system when making critical decisions on asset development and concept type during front-end evaluation.

We use separate models to define the competitiveness of the drilling program and the competitiveness of the project's facilities scope. The benchmark controls for the size of the anticipated production stream (e.g., larger production streams are correlated with a lower cost per barrel). The benchmarks for this model are intentionally not concept-specific and not normalised for complexity.

Low facilities cost per barrel may be caused by development that takes advantage of pre-existing processing facilities. On average, subsea developments have lower $/BOE costs. Low drilling costs per barrel with respect to the industry mean are either a result of lower drilling costs than usually achieved in the region or higher average hydrocarbon recovery per well.

TOTAL FACILITIES COSTS

The total facilities cost metric normalises for anticipated life-of-project production stream, region, and facility complexity. This assessment is often useful for concept selection purposes. The project complexity is, in most cases, an uncontrollable factor for a chosen concept. The analysis of total facilities cost indicates whether the concept chosen is competitive with concepts of similar complexity, region, and production streams. It includes adjustment for water depth and concept details.

PLATFORM COST

Our Platform Model normalises for functional complexity, accounting for such factors as throughput, separation streams, corrosive fluids, pumping power, water treatment, type of drill rig, and necessary auxiliary features such as power generation, helideck, and living quarters. The model also adjusts for location, water depth, and design wave height. This model intentionally does not normalise for anticipated life-of-project production streams.

PIPELINES COST

Industry benchmark costs for pipelines are normalised to a scope (length, size, water depth, and region) similar to the project. Right-of-way costs and associated environmental and permitting fees are included. Riser costs are excluded from both project costs and from the model.

The model does not explicitly correct for trenching and exotic materials. The model simply compares the pipelines to others performing similar duties in the region. Other pipelines may either have to be trenched or made heavier to ensure stability.

The choice of exotic materials is made on economic grounds to avoid high corrosion allowances. Our model is based on projects that did not require exotic pipeline materials, so we make a manual adjustment to benchmarks for projects for which exotic materials are essential.

FPSO COST

Our FPSO Model normalises for functional complexity, accounting for such factors as throughput, separation streams, corrosive fluids, pumping power, water treatment, and necessary auxiliary features such as power generation, helideck, and living quarters.

SUBSEA SYSTEM COST

The cost for a subsea system includes flowlines, umbilicals, and subsea trees. The subsea analysis is performed using a statistical model that normalises flowline and other subsea hardware specifications, location, and water depth. The subsea benchmark also includes riser costs. We do normalise for trenching cost and rock-dumping cost.

The choice of exotic materials is made on economic grounds to avoid high corrosion allowances. Our model is based on projects that did not require exotic flowline materials, so we make a manual adjustment to benchmarks for projects for which exotic materials are essential.

CONTINGENCY FOR NEW-BUILD FACILITIES

Our contingency model is based on the philosophy and assumption that the project team uses industry average base estimating practices. If a project uses estimating practices that are biased toward more conservative base estimating practices than Industry, this may result in a lower contingency requirement than the industry benchmark.

The IPA contingency model is normalised for changes in escalation and currency exchange, and is normalised for the quality of FEL, technical innovation, and company experience in the host country.

DRILLING CONCEPT COST EFFECTIVENESS

The Concept Cost Effectiveness Model determines what Industry, on average, would spend on a similar project, not taking into account what *type* of concept was designed to develop the asset. In other words, the model is based on the uncontrollable factors that make up the asset (such as location, water depth, reserve size, and reservoir complexity, RCI).

DRILLING COMPONENT COST EFFECTIVENESS

The Component Cost Effectiveness Model determines what Industry would typically spend on a project based on the way the project team decided to *execute and design* the development. This model predicts the cost of a certain development plan regardless of whether it is the “right” plan. Inputs include number of wells, TVDBML, well complexity, type of rig, water depth, location, reach, and well type. The major driver of the $/BOE and Concept Cost Effectiveness Models is reserve size. Because this model is intended to look strictly at the development design and provide a cost benchmark, the major driver is well count. However, there has been an important refinement and improvement to this model when compared to previous Component Cost Effectiveness well models: This Component Cost Effectiveness Model is able to benchmark programs that include wells that are reentries of preexisting wells.

SCHEDULE EVALUATION

Execution Schedule

The execution duration is measured from the start of detailed engineering to first production. One of the most significant drivers of this model is the estimated cost of the project, which essentially measures the amount of work that has to be performed. The model also takes into consideration the water depth of the project, but does not include any allowance for external factors that may alter the schedule, such as scope changes, cash flow restrictions, labour shortages or stoppages, equipment delivery delays, or unusually bad weather. The model assumes single-shift operations onshore of 40 to 45 hours per week and double 12-hour shifts offshore.

Drilling Duration

The Drilling Duration Model yields the industry average drilling duration (in days) for a particular drilling program. Similar to the Component Cost Effectiveness Model, this model predicts how long a drilling program should take based on the way the project has been designed. This can be extremely useful when trying to tell if a project has an aggressive schedule target. There is a popular opinion that, because time-dependent costs are such a large amount of total cost, the duration index should yield the same index as the Component Cost Effectiveness Model. However, this may not be the case for multiple reasons. For instance, if a well is directionally complex, a team may have to use more expensive technology to drill highly directional wells, yet the time it takes to drill these wells may not be considerably more than a simple well, depending on the region. SMART wells add considerably to cost, but not necessarily to duration.